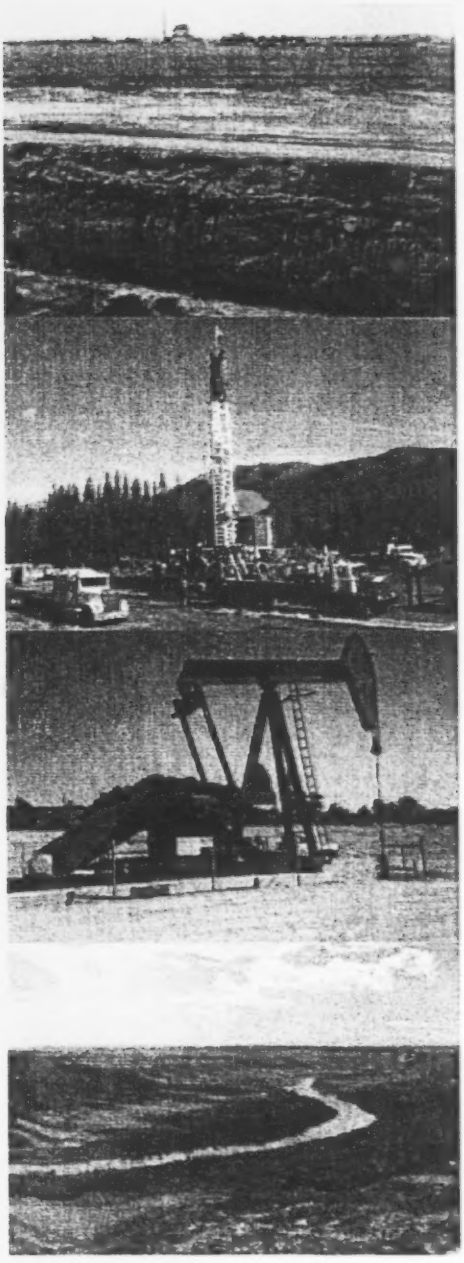


The Potential for Coalbed Methane (CBM) Development in Alberta

Prepared for
Alberta Department of Energy

by
J.J. HEATH & Associates

September, 2001

104-02446/

PREFACE

Market conditions in North America are ripe for growing supplies of natural gas…demand is strong, prices remain reasonable, and there is excess export pipeline capacity.

The Alberta Department of Energy commissioned a study in January 2001 to examine the potential for Coalbed Methane (CBM) Development in Alberta. An advisory committee of representatives from Alberta's oil and gas industry participated which included: Mr. Wayne Smith – Alberta Energy Corporation, Mr. Brian Morse – Suncor Energy Inc., Mr. Roger McMechan – Petro Canada, Mr. Colin McKenny – Fording Coal Limited, Mr. Val Mirosh – TransCanada Pipelines Limited, Mr. Douglas Marjerrison – BP Canada Energy Company, Mr. Stephen Kaufman – Suncor Energy Inc., Mr. Kin Chow – PanCanadian Petroleum Limited, Mr. Frank Basham – Talisman Energy Inc. and Mr. John Benton – Gulf Canada Resources Limited. Assistance in the consultation approach was provided by Alberta Energy staff, including: Mr. Stan Wenger – Chairman, Mr. Mike Ekelund – Co-Chairman and Ms. Sharla Rauschning.

The Potential for Coalbed Methane Development in Alberta reflects the recommendations of the CBM Advisory Committee. It provides recommendations to government on fiscal, regulatory and other changes that will help advance the development of Alberta's CBM resources.

As such, this report is a culmination of strong stakeholder interest and input. Indebtedness is due to the excellent and dedicated Advisory Committee whose responsibility it was to ensure an objective, independent analysis, which addressed all the critical aspects of CBM potential for Alberta. Gratitude is also extended to the survey participants (industry, government, research and focus groups), the Sub-Committee Chairs, Co-Chairs and Members, the CBM Workshop Participants and Breakout Session Leaders, and the many producers and regulators in the United States who openly shared their experiences and suggestions.

This report does not reflect Alberta Government policy or direction at this time. Alberta Energy and Utilities Board Informational Letter (IL 91-11) in Appendix I of this report sets out the existing regulations for development in Alberta.

Front cover photos, from top to bottom.
Courtesy: David Hughes, Geological Survey of Canada
Layne Christensen Canada Limited
Anadarko Petroleum Corporation
David Hughes, Geological Survey of Canada

THE POTENTIAL FOR COALBED METHANE DEVELOPMENT IN ALBERTA

CONTENTS

I. EXECUTIVE SUMMARY 1

II. BACKGROUND AND STUDY PROCESS 5

III. CRITICAL ASPECTS OF COALBED METHANE DEVELOPMENT POTENTIAL 13

IV. UNITED STATES BASIN EXPERIENCE 24

V. ESTABLISHING AN ECONOMIC FRAMEWORK FOR SUSTAINABLE DEVELOPMENT 46

VI. OBSERVATIONS AND CONCLUSIONS 58

APPENDICES

I. Alberta Energy and Utilities Board Informational Letter 91-11 and Related Regulations Pertinent to Coalbed Methane 62

II. United States Section 29 Tax Credit 70

III. Stages of Coalbed Methane Production 71

IV. Powder River Basin, United States Geological Survey 72

BIBLIOGRAPHY

I. EXECUTIVE SUMMARY

Alberta Energy commissioned a study in January 2001 to examine the potential for coalbed methane (CBM) development in Alberta. The objectives of the study were to develop an understanding of the potential CBM reserve base, to examine the environment necessary for appropriate economic development of CBM, and to determine potential strategies for Alberta Energy to consider in development of the resource.

There are a number of reasons why natural gas from Alberta's coal resources is emerging as a topic of increasing interest among industry stakeholders:

- the forecast for reasonable natural gas prices and continued growth in energy demand, particularly in the power generation sector;
- the Alberta Energy and Utilities Board (EUB) estimates remaining established reserves of natural gas at 43 trillion cubic feet (tcf);
- the National Energy Board predicts that unconventional supplies of natural gas will be required by 2008 to meet rising demand; and,
- relative to the very large in-situ resource estimates of CBM (60 tcf in the Foothills region and 350 tcf in the Plains region), the recoverable reserves are estimated to be between 0 and 135 tcf.

The study process developed as follows:

Phase I
- establishment of a stakeholder-led advisory committee;
- review of existing assessments and a stakeholder survey; and,
- preparation of a preliminary report.

Phases II & III
- technical, economic and fiscal analysis;
- examination of the requirements for sustainable CBM development;
- organization of a CBM workshop;
- review of 'Best in Class' experiences; and,
- preparation of a final report.

The survey was structured to address three critical information areas:

(i) the past CBM experience of industry stakeholders;
(ii) their current corporate philosophy on CBM and input on related technical, economic and environmental issues; and,
(iii) their input on variables required for establishing an economic framework for sustainable development.

The survey results contained in the Phase I report noted that the past experience of the participants in Alberta focused on the Plains area, primarily within the Mannville and Ardley coal zones, with a secondary focus being the Coalspur and Brazeau Formations of the Foothills. Most of the companies surveyed indicated that their corporate plans included the development of CBM, citing the 'size of the prize' as the primary reason.

Industry participants surveyed provided numerous comments on the critical technical, economic and environmental issues surrounding CBM development. As a result, the CBM Advisory Committee prioritized these issues and directed that they be examined further through a Sub-Committee process and workshop to broaden the scope of stakeholder input.

These steps resulted in the establishment of five major Sub-Committees and the related workshop breakout sessions to address the priority issues and associated impediments in the following areas:

- technical issues - much of the focus being the need for and lack of data, and the need for recognition of the unique characteristics of CBM;
- land access and tenure issues - in particular, the need for large contiguous land tracts and the existing administrative and regulatory constraints to land assembly;
- water disposal and diversion issues - with priority concerns around the need to dewater non-saline aquifers associated with coal seams and the potential for surface discharge;
- non-technical issues - a way for CBM stakeholders to initiate regulatory change, access to information and confidentiality issues, the need for research and development as well as public consultation, all within a relatively narrow window of opportunity given competing energy projects; and finally,
- economic issues - CBM plays are high risk, capital intensive, low-return projects with long-term payouts.

The workshop breakout sessions also identified a wide range of potential mitigation strategies. With these CBM issues and strategies in mind, field trips to the United States (U.S.) were undertaken to meet with regulators and producers to compare the experience they have gained over the past 20 years. Some of the salient observations and lessons learned included the following:

- no two CBM basins are the same;
- having good baseline resource inventory data is critical;
- evolving management, drilling and completion techniques have and will continue to enhance the economic understanding; and,
- since there is no publicly recognized commercial production of CBM in Alberta, stakeholders have the opportunity to learn from the technical, economic, and environmental strategies which have been developed and tested in the U.S.

Taking into consideration the priority issues identified through the survey and consultative process of this study, along with the experiences shared by U.S.

stakeholders, the following mitigation strategies suggested by industry may be applicable to CBM development in Alberta.

Potential Technical Mitigation Strategies

There is no substitution for drilling, continuous research and data analysis, and the public dissemination of this knowledge in order to resolve the technical barriers and identify the optimal drilling, completion and production technologies (balanced with the appropriate consideration for confidentiality). 'CBM wells' must be classified as such and the associated information requirements should indicate achievable production rates, gas contents of the coals, and the composition of the gas.

Potential Land Access and Tenure Strategies

The challenge of assembling large contiguous tracts of land, needed to achieve sufficient scale to be economically attractive and provide expansion opportunities throughout the various stages of development, has largely been sorted out in the U.S. through the marketplace. In Alberta, this could require both interim and longer-term solutions. Short-term resolutions could include development of clear definitions for test wells and experimental schemes, flexibility around Section 17 of the *Petroleum and Natural Gas Tenure Regulation*, and a review of the rules as they apply to continuation.

Well spacing requirements will need to be reviewed and revised, as the current stipulation of one well per section is insufficient for the degree of communication necessary between well bores to optimally depressurize and stimulate CBM production.

Further review is required of the benefits and implications of unitization.

Potential Water Disposal and Diversion Mitigation Strategies

Current regulations governing the disposal and/or diversion of water in Alberta pose significant obstacles and potentially are CBM 'project breakers'. Inherent to CBM production is the need to dewater the coal seams. As noted by the participants in the CBM Workshop, this suggests that policy changes are required to allow for the dewatering of non-saline aquifers as well as consideration of surface discharge.

Baseline studies on a project basis will assist in developing the appropriate water handling options.

Potential Non-technical Mitigation Strategies

Consistent with what the Alberta stakeholders identified through the CBM workshop, U.S. experience concurs with the importance of multi-stakeholder task groups in order to enhance coordination, communication and cooperation regarding all aspects of CBM development.

Ongoing research and development of non-site-specific issues (i.e. water disposal options).

Potential Economic Mitigation Strategies

The major economic hurdles associated with the development of a CBM industry in Alberta relate to expectations of low productivity, significant upfront costs and long payout periods. Stakeholders suggested the need for a fiscal and economic framework, which recognizes the specific incremental operating and capital costs associated with CBM production.

A fair and reasonable incentive should be considered which would encourage the industry to drill, for a sufficient time period, to gain the necessary technical understanding of the potential for producing CBM in Alberta.

The outlook for the development of a sustainable CBM industry in Alberta is positive. The province has vast resources of coal, estimates of significant CBM recoverable reserves, a highly skilled workforce that is widely recognized for their expertise and adaptability, an extensive and efficient natural gas distribution system, a growing demand for natural gas resources, expectations for reasonable natural gas prices, and incremental export pipeline capacity. It is important, therefore, to take time to acknowledge the hurdles and design the regulatory and economic strategies in a sound and reasoned manner.

Industry has suggested there is a need to:

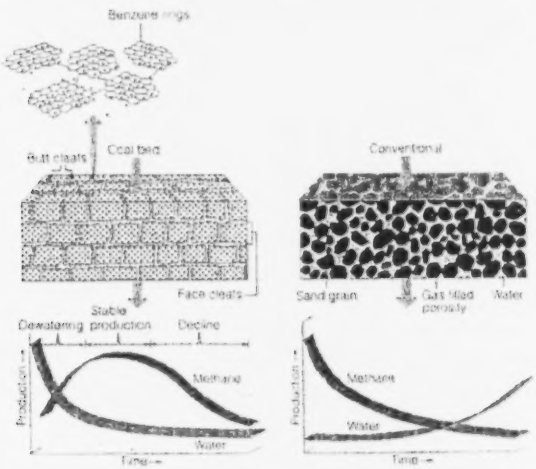
- determine a fair and reasonable manner of encouraging drilling;
- establish a CBM Advisory Group to examine emerging regulatory/policy requirements;
- encourage baseline analysis (e.g., methane gas seepage and basin-wide/watershed studies) and continuous research and development of the coals, the coal reservoirs, the sweet spots, drilling and completion technologies and environmental aspects (water, air, noise, wildlife), etc.;
- develop the economic framework for ongoing production forecasting as data becomes available;
- examine the impact of CBM development on power requirements and related infrastructure needs;
- continue the examination of enhanced CBM production implications;
- examine administrative manpower requirements; and finally,
- encourage the public consultation process through such initiatives as workshops, road/trade shows, a CBM website, and development of a 'made in Alberta' CBM pamphlet.

The next steps toward development of a sustainable CBM industry will be critical.

II. BACKGROUND AND STUDY PROCESS

Vast amounts of CBM are present in Alberta's extensive coalfields. CBM is natural gas produced as a by-product of the coal formation process, stored on the internal surfaces of the organic matter. Coal has the ability to store more than six times the volume of gas than other conventional natural gas source rocks because of its large internal surface area. The amount of CBM generated and stored in coal is dependent upon a number of geological criteria including the coal rank, composition and quality, thickness of the seams, reservoir depth and thermal history, and reservoir permeability.[1] Other by-products of the coalification process include water, carbon dioxide (CO_2) and nitrogen (N_2). The presence of water in the coal formation, which provides an indication of the permeability of the coal, and the regional hydrodynamics, affect the producibility of the CBM. An extensive cleat system (face and butt cleats) is required to provide the permeability and flow path to the wellbore. CBM wells can almost be considered water wells at the front end of most projects and only become gas wells once the reservoir is depressurized by removing the water, allowing the methane to desorb from the coal as shown in Figure 1.

Figure 1
Gas Storage and Production, Conventional versus CBM



[1] F.M. Dawson, D.L. Marchioni, T.C. Anderson, W.J. McDougall, *An Assessment of Coalbed Methane Exploration Projects in Canada*, (Her Majesty the Queen in Right of Canada, 2000).

There are a number of reasons why natural gas from Alberta's coal reservoirs is emerging as a topic of increasing interest among industry stakeholders:

- Reasonable natural gas prices are forecast (see Figure 2) with continued growth in energy demand, particularly in the power generation sector.
- The EUB estimates remaining established reserves of natural gas at 43 trillion cubic feet (tcf) with annual production of 5 tcf.[2]
- The National Energy Board (NEB) predicts that unconventional supplies of natural gas will be required by 2008 to meet rising demand (see Figure 3).[3]
- Canada has vast reserves of coal (see Figures 4 and 5) and ranks fifth in the world behind Russia, China, the U.S. and Australia; Alberta has remaining estimated reserves of 34 billion tonnes, with annual production of 0.034 billion tonnes.[4]
- The potential 'size of the prize'…estimates of CBM resources vary greatly. The extensive deformation of the coals in the Foothills makes it more difficult to quantify the CBM potential even with available drilling information and surface mapping. More extensive evaluation has been done to quantify the potential in the Alberta Plains where there has been less distortion of the coal seams. Relative to the very large insitu resource estimates (60 tcf in the Foothills and 350 tcf in the Plains), the recoverable portion is estimated to be somewhere between 0 and 135 tcf (noting that there has been no economic production published to date).[5]

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[2] Alberta Energy and Utilities Board, *EUB Backgrounder: Alberta Reserves 2000 and Supply/Demand Outlook 2001-2010*, (Information Services, EUB website: **www.eub.gov.ab.ca**), p.3.
[3] National Energy Board, *Canadian Energy Supply and Demand to 2025*, (Her Majesty the Queen in Right of Canada, 1999), p.49.
[4] Alberta Energy and Utilities Board, *EUB Backgrounder: Alberta Reserves 2000 and Supply/Demand Outlook 2001-2010*, (Information Services, EUB website: **www.eub.gov.ab.ca**), p.4.
[5] Discussions with David Hughes, Geological Survey of Canada.

Figure 2

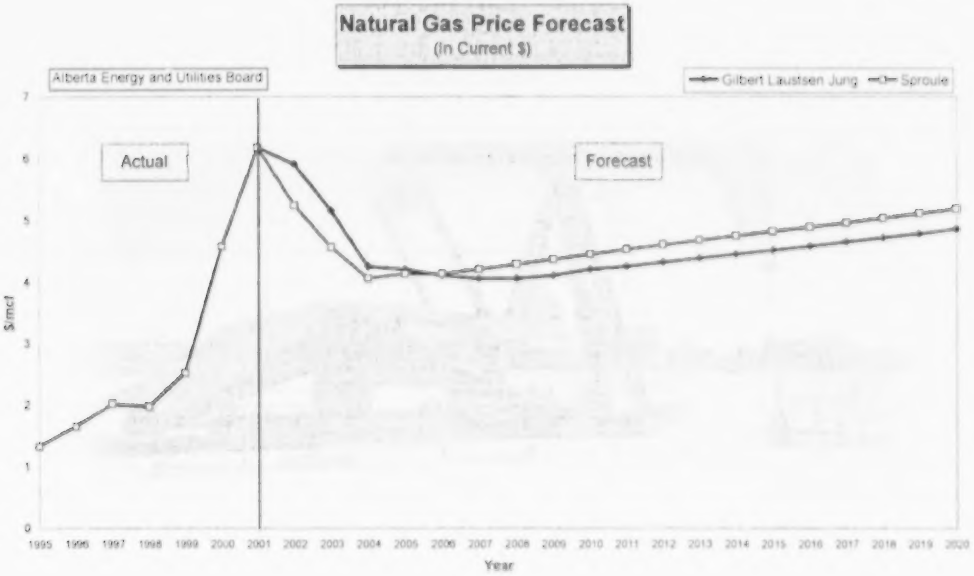
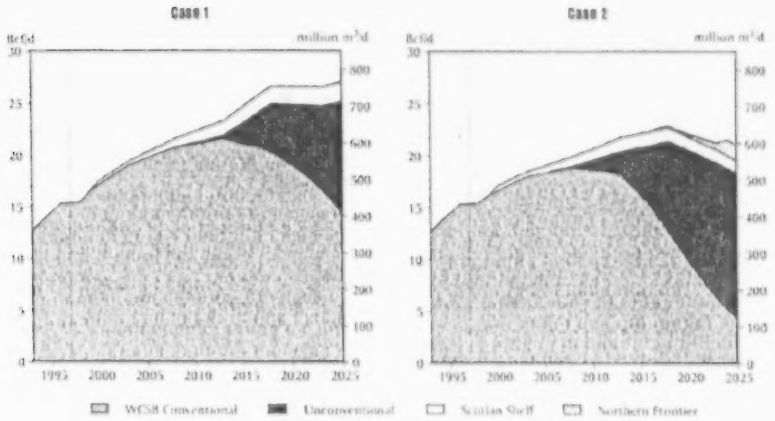
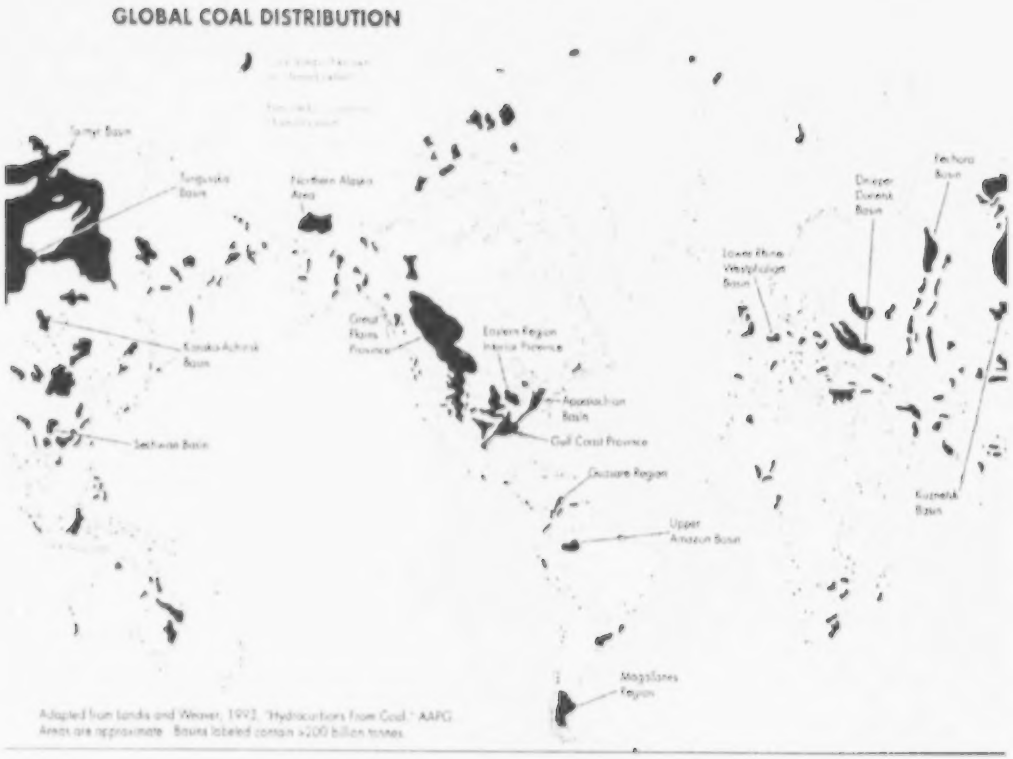


Figure 3
Total Canadian Production



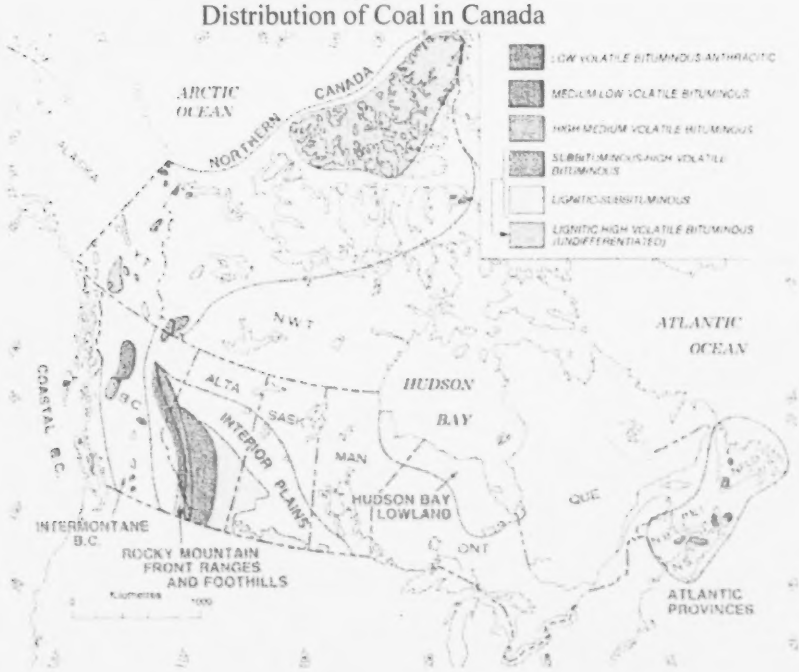
Source: National Energy Board

Figure 4


GLOBAL COAL DISTRIBUTION
Tunguska Basin
Kuznetsk Basin
Gulf Coast Province
Magallanes Region
Adapted from Landis and Weaver, 1992, "Hydrocarbons From Coal," AAPG
Areas are approximate. Basins labeled contain >200 billion tonnes

Source: Gas Research Institute

Figure 5
Distribution of Coal in Canada



Source: Geological Survey of Canada

Given the increasing demand for natural gas supplies, natural gas prices, and the drive to grow Alberta natural gas reserves, Alberta Energy commissioned a study in January 2001 to examine the potential for CBM development in Alberta. The objectives of the study were to develop an understanding of the potential CBM reserve base, to examine the environment necessary for appropriate economic development of CBM, and to determine potential strategies for Alberta Energy to consider in development of the resource. The study process developed as follows:

Phase I

- establishment of a stakeholder-led advisory committee to ensure the study was performed in an independent and objective manner and addressed all the critical aspects of CBM development potential for Alberta;
- review of existing assessments and a stakeholder survey; and,
- preparation of a preliminary report.

Phases II & III

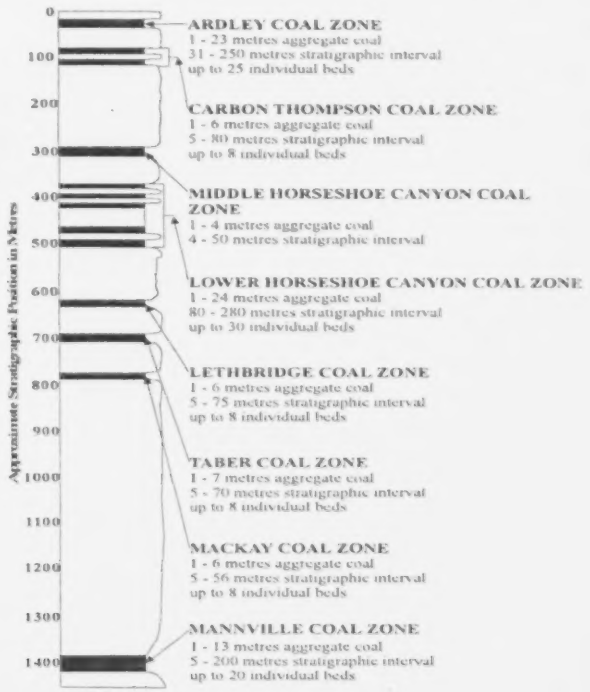
- technical, economic and fiscal analysis;
- examination of the requirements for sustainable CBM development;
- organization of a CBM workshop;
- review of 'Best in Class' experiences; and,
- preparation of a final report.

The Phase I Report is a synopsis of the information provided by CBM stakeholders through a survey, which involved one-on-one meetings. The survey was structured to address three critical information areas:

(i) the past CBM experience of industry stakeholders;
(ii) their current corporate philosophy on CBM and input on related technical, economic and environmental issues; and,
(iii) their input on the variables required for establishing an economic framework for sustainable development. Thirty-seven key Alberta CBM stakeholders participated in the initial survey process, which culminated in the preliminary report.[6] Following are highlights of the Phase I Report prepared in March 2001.

Experience

Of the 30 energy companies surveyed, 17 have been involved in CBM initiatives in Alberta, eight in other parts of Canada, and 13 have had international experience in the U.S. and elsewhere. Most of the activity in Alberta occurred in the late 1980s to mid 1990s, with a noticeable resurgence in the last six months. The majority of this experience has been focused in the Plains area, primarily within the Mannville and Ardley coal zones. In two-thirds of the exploratory drilling initiatives, the primary focus was on CBM, with the remainder focused on conventional hydrocarbons where CBM was a fallout or piggyback project.



Source: Geological Survey of Canada

[6] It is important to note that the survey process continued throughout the course of the study and that over 50 CBM stakeholders were interviewed.

Current Status and Company Philosophy on Coalbed Methane

Nearly three-quarters of the companies indicated that the development of CBM had a place in the future of their corporate plans, citing the 'magnitude of the prize' as the underlying objective. Of the stakeholders in a position to comment on Alberta's competitive position relative to other jurisdictions, most noted that the Alberta regulatory structure and fiscal environment allows producers to be more competitive than for similar operations in British Columbia. For the most part, when compared with U.S., Alberta was felt to be less competitive, due largely to the existence of the Section 29 Tax Credit, which is scheduled to sunset in 2002. *[See Appendix II]*

The industry participants surveyed provided numerous comments on the critical technical, environmental, economic, and societal issues surrounding CBM development, with CBM being described by many as either a 'technical' play or an 'economic' play. From a technical standpoint, they stressed the risk associated with the lack of sufficient technical data to ensure commercial extraction from the resource base, the shortage of expertise to interpret the data, and the need for further research and a better understanding of appropriate drilling and completion technologies, whether new or adapted. Respondents also emphasized the necessity of reviewing current water disposal issues.

At the core of the potential for CBM development in Alberta is economics. Stressed repeatedly was the issue of access to land, as large contiguous land blocks are deemed essential to any viable project. CBM plays were described as high risk, capital intensive, low-return projects with long-term payouts; therefore, participants sought assurance that the regulatory process acknowledges these underlying characteristics.

Industry expressed a strong commitment to environmental practices although it was felt that CBM development has the potential to be less intrusive than conventional oil and gas projects. It is important to note that the potential for enhancing CBM production through the injection of CO_2 was considered to have both economic and environmental merits by increasing production volumes while, at the same time, sequestering such greenhouse gases as carbon dioxide, nitrogen and flue gas. Finally, societal issues were felt to be no different than for any oil or gas operation.

Establishing an Economic Framework for Sustainable Development

Since there is no known commercial production of CBM in Canada, the financial statistics provided by the survey participants and included in this report, have been drawn, for the most part, from historical cases in the U.S. and other known coalbed producing countries. The financial statistics provided by the participants also reflect projected costs, based on their related hydrocarbon producing activities in Alberta.

The final section of the survey addressed the thoughts of the industry participants on what the potential role of the Alberta Government should be in the development of CBM. Most participants stressed the need for government to take a leadership role of encouragement and underlined the urgency of taking the appropriate action. They noted that companies will continue to examine all opportunities to grow natural gas production

and reserves, but suggested that with an announcement of any new capital intensive project, such as a natural gas pipeline out of the north, the ability to access capital for CBM projects would become much more difficult. All the stakeholders noted the 'need to drill' as it is only through drilling activity that the requisite data will be obtained which is necessary to fully understand and optimally develop Alberta's CBM resource base.

III. CRITICAL ASPECTS OF CBM DEVELOPMENT POTENTIAL

The survey process identified a number of critical technical, economic and environmental challenges. The following outlines the common issues historically encountered by the CBM survey participants having experience in CBM exploration and development activities.

Technical Issues

- permeability;
- lack of existing data;
- lack of technical experience;
- high maintenance requirements;
- implications of current well-spacing requirements;
- impact of current stimulation procedures on the reservoir;
- well-bore damage; and,
- water disposal processes.

Environmental Issues

- all those currently related to conventional oil and gas operations
- (health, safety and environment);
- impact on landscape (and community perception thereof); and,
- water disposal requirements.

Economic Issues

- land tenure and access to large contiguous land areas;
- large upfront capital costs and associated risk factors;
- time and uncertainty of dewatering process;
- water disposal costs;
- requirements for blow-out prevention equipment (BOPs);
- expensive lifting costs;
- well-spacing requirements; and,
- research and development costs.

Societal Issues

- all those currently related to the oil and gas industry.

CBM Sub-Committees

Having identified the above CBM related issues, the Advisory Committee prioritized the major hurdles and five Sub-Committees[7] were structured to review the issues, identify the major impediments to development, and discuss potential resolutions. Highlights of the discussions and observations of the five Sub-Committees were as follows:

Technical Sub-Committee

Discussion and Observations

It is paramount to determine the permeability of potential CBM reservoirs in Alberta.

Strongly underlined was the need 'to drill a lot of cheap holes' to get a better technical understanding of the resource.

The rules and regulations accompanying a drilling application for CBM should facilitate the gathering of the technical understanding required to better understand the potential for producing this resource. If classified as 'CBM wells', the information gathered should indicate achievable production rates, the gas content of the coals, and the composition of that gas.

It was recognized that the more information gathered through drilling, the better the understanding of the need for potential changes to regulations relating to such things as blowout prevention equipment requirements, etc.

Also noted was the fact that in order to encourage the industry to develop, there may be a need for a longer confidentiality period.

Suggested Resolutions

- entice drilling;
- ensure CBM wells are designated as such;
- ensure appropriate data is submitted and housed at the EUB;
- address land access and tenure concerns;
- establish royalty relief (it was suggested that something similar to the oil sands royalty schemes should be considered);
- educate the public; reduce the lack of understanding surrounding CBM; and,
- reissue booklet describing CBM.

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[7] The CBM Sub-committees were comprised of Advisory Committee members as well as representatives from most of the companies interviewed during the survey process.

Land Access and Tenure Sub-Committee

Discussion and Observations

CBM development was noted as being a multi-phase, multi-year process that requires large upfront capital investment.

Large contiguous land blocks, with extended terms, were suggested as necessary in order to achieve sufficient scale to be economically attractive and provide sufficient expansion opportunities throughout the various stages of development, considering the technical and geological risk to CBM exploration in the Western Canada Sedimentary Basin.

Most committee members agreed that in Alberta there is a lack of availability of large contiguous land blocks and that the current land ownership in the more mature conventional areas makes it difficult to acquire or assemble large blocks.

Farm-ins, changing the rules for continuation and the potential for shallow rights reversion were raised as possible solutions.

As there were varying solutions suggested around the table, the Chairman questioned whether or not there was a need for a broader level of input to decide what options should be recommended. A CBM seminar/workshop was noted as one way to broaden the input but it was also strongly agreed that the Sub-Committee should partner with other industry representatives to investigate and develop a 'laundry list' of solutions. When it was noted that any land tenure changes would eventually have to be considered by the Tenure Advisory Forum and that a meeting of the Forum was scheduled for May 24th, it was suggested that the committee try to arrange to have a representative speak at the meeting. A representative was selected who brought forward the CBM related land access and tenure concerns noted by the Sub-Committee and the suggested need for industry to work with government and related regulatory agencies, through their various associations, to identify potential changes to the land tenure regime that would encourage sustained CBM exploration and development.

Suggested Resolutions

The Sub-Committee believes there is a general industry consensus at this time that the existing land tenure system, in particular the way CBM rights can be retained by production from other zones, impairs the level of CBM exploration activity.

The Sub-Committee recommends that government, through Alberta Energy and the EUB, as appropriate, work together with industry (primarily through the joint government/industry Tenure Advisory Group) to identify potential changes to the tenure system and related regulatory system that would encourage increased CBM exploration.

The Sub-Committee recommends an approach that solicits as broad a response as possible to develop creative solutions.

Water Disposal Sub-Committee

Discussion and Observations

The discussions began with a review of the current water disposal regulations and the role of the EUB. It was suggested and agreed that the committee should look at both water disposal and diversion. It was noted that if the committee wanted to discuss both aspects of this issue that a representative from the Alberta Department of Environment (AENV) should be involved. It was indicated that under the *Oil and Gas Conservation Act* and Regulations, the EUB is responsible for the gathering, storing and disposal of water produced in conjunction with oil and gas. AENV gets involved in anything other than putting back the water into the reservoir below the base of useable ground water. Thus, anything involving discharge to the surface would likely fall under the jurisdiction of AENV.

There is some overlap with the roles of the EUB and AENV. Useable water is defined as having less than 4000 parts per million total dissolved solids (ppm/tds). For the handling of produced water below 4000 milligrams per litre of dissolved solids, AENV may require a diversion permit. Oil and gas producers are not currently allowed to use surface evaporative ponds. Surface discharge was allowed in the past but it was difficult to manage so policy was changed in 1999 that made surface disposal an unacceptable practice. However, coal producers are allowed to put water in their tailings ponds.

Regional reinjection, that uses surface ponds, is not currently allowed but if the regulations changed, the EUB would be involved. If true surface discharge (not storage tanks which would be EUB regulated) is being considered, AENV would be involved. When dealing with the production of water under 4000 ppm, one needs to work through both the *Water Act* proper and possibly through the *Alberta Environmental Protection and Enhancement Act (AEPEA)*. Two approvals would be required…one to comply with the *Water Act* and the second to comply with *AEPEA*. (Note: water produced in conjunction with oil and gas is exempt from *AEPEA*.)

If disposing of water below 4000 ppm, companies may need permits from both AENV and the EUB. Any handling of water on the surface, such as collecting run-off, requires application for diversion under the Surface Water Quality Guidelines, which are outlined on AENV's website at:
http://www3.gov.ab.ca/env/protenf/publications/SurfWtrQual-Nov99.pdf

Over the course of the meeting, the following four water disposal/diversion options were discussed:

(i) deep well;
(ii) surface disposal;
(iii) evaporation ponds; and,
(iv) commercialization.

Further issues of note included:

- the time it takes for water diversion approval; the need for baseline studies to collect water data associated with any area impacted by CBM development;
- potential water contamination issues; costs associated with water disposal/diversion and the potential for royalty relief and/or recognition of CBM related costs within the Gas Cost Allowance; and,
- the need for further education about the appropriate options related to water withdrawal, disposal and/or diversion.

The Sub-Committee agreed that it would be inappropriate to suggest any water disposal/diversion resolutions without subsequent representation from AENV.

Non-technical Sub-Committee

Discussion and Observations

The uniqueness of CBM relative to conventional natural gas production was discussed. CBM was viewed as being a high-risk industry, very capital intensive with a low rate of return and long payout. It was noted that CBM was similar in nature to a heavy oil steam assisted gravity drainage Steam Assisted Gravity Drainage (SAGD) project where the risk was in the costs and in the technology not in whether or not there are reserves. It was recognized, however, that treating CBM like oil sands from a fiscal perspective would segregate it from conventional gas. There are positives and negatives to the 'revenue minus cost' scenario…different costs could be recognized and royalty rates could be lower than the current gas rates. Alternately, it was pointed out that under the current Gas Cost Allowance, a company can have rolled in eligible costs, a low productivity rate, and costs recognized at a corporate level; in other words, the eligible costs from CBM could be included with the costs related to conventional natural gas and deducted from the total gross royalty amount. On the other hand, it was mentioned that this would not have any advantage to a company, which didn't have royalties to write off against.

From a regulatory perspective, the focus was on cost controls and methods that could help to streamline the process while recognizing the unique characteristics of CBM. Regulations around blowout prevention equipment and project data confidentiality were noted as issues that should be reexamined in relation to CBM. Issues such as the grouping of well licenses were noted as likely

achievable but that first and foremost it is important that industry understand what the current regulations are. Underlined was the fact that if CBM is going to be around for 30 to 50 years, we need to make sure that the appropriate regulations and incentives are put in place at the outset.

Other areas noted as having differences from conventional natural gas drilling were that of flaring or venting and water production, disposal and diversion. Currently, companies can flare between 200 and 600 10^3m^3 and there is not a defined time restriction on the flaring. Venting is discouraged even more so than flaring. Again, similarities were pointed out regarding the number of wells required for reinjection in the CBM industry and the heavy oil industry and the fact that in the heavy oil industry, reinjection is an eligible cost for reduction in heavy oil royalty calculations.

Some discussion evolved around CBM ownership. It was observed that who owns the gas in the coal still is an issue in many boardrooms even though it is recognized that on Crown lands the oil and gas leaseholder is the owner of the CBM.

Suggested Resolutions

- A fiscal framework that allows the industry to function while recognizing the uniqueness of the CBM industry.
- Some form of 'incentive' to promote establishment of the industry.
- More public education and some sort of proactive review of regulatory issues.
- A re-examination of flaring and flexibility of water handling, issues which should be recognized as unique, particularly the risks and costs.

Economics Sub-Committee

Discussion and Observations

This Sub-Committee also recognized the differences between CBM and conventional natural gas, in particular, the high upfront costs, the dewatering period, the long payout and discussed what fiscal/royalty relief could help in reducing related risks. One solution suggested was financial relief for upfront exploration costs…costs associated with determining the permeability of the basin, which may mean a sizable number of exploration wells. Other suggestions were royalty holidays and some sort of compensation for the CBM-specific incremental costs.

A question raised was how companies measure the exploratory success rate in an exploration play. It was noted that in a CBM project, it may take 20 wells to determine the permeability, thus the suggestion that the 'entire pilot project' be included as 'exploratory'.

Costs that were indicated as CBM specific and should be included for some sort of relief were as follows:

- extra wells for pilot stage;
- new and specific technology focused on CBM;
- some artificial lift;
- storage facilities;
- dual flow lines;
- compression;
- additional facilities to separate water and gas;
- water disposal/diversion;
- additional environmental costs (surface facilities);
- incremental costs related to completion; and,
- additional facilities.

It was noted that with regards to royalties, there are a number of existing programs that might be applicable to CBM, an example provided was the Deep Gas Royalty Holiday.

Consideration for a different royalty formula for CBM was not considered a constraint at this point in time, however, it was suggested that whatever the decision, it would need to be simple and easy to administer for both industry and the Crown.

The aspect of how to distinguish CBM production from neighboring natural gas reservoirs (e.g. sands) was raised. It was questioned whether a CBM specific royalty could be established, if there was some way to distinguish the CBM from the neighboring gas. On the other hand, it was queried as to whether industry would really want CBM treated uniquely, noting that under the current Gas Cost Allowance, industry can apply all applicable natural gas costs on a corporate basis prior to paying royalties.

Lower royalties were suggested but it was questioned whether reducing the royalties to below what would likely result should CBM production rates fall within a 'low productivity' environment, would be enough to help in establishing the industry.

It was questioned whether or not government would consider an incentive for sequestration of CO_2 in enhanced CBM projects, in the form of credit against the cost associated with gathering and processing the CO_2.

Interest was expressed in a potential tax credit associated with an 'experimental' status, suggesting that perhaps all CBM production could be considered as experimental until a specific provincial production level is achieved. Also mentioned was the possibility of maintaining experimental status until a project becomes commercial, where commercial is defined as achieving payout.

Further incentives reiterated throughout the discussion included compensation for related CBM-specific capital expenditures which was the preferred option of the Sub-Committee, recognition of CBM related water costs in the Gas Cost Allowance, and the application of any incentives considered to suspended conventional wells which are recompleted as CBM wells.

It was stressed that if the interest is in 'kick-starting' a CBM industry, any incentive should be in place prior to, or at the exploratory stage.

It was suggested that industry may want to keep an open mind with respect to consideration of a revenue minus cost (R-C) royalty scenario (which would separate the resource out from conventional gas), given the potential for using a current incentive that could incorporate CBM costs, without separating this resource out.

The issue of timing was stressed, reflecting the fact that industry is currently and actively finalizing corporate plans related to CBM; thus, the Sub-Committee observed that within this fiscal year some kind of incentive program needs to be established if the objective is for a CBM industry to be launched in Alberta.

Suggested Resolutions

- Consideration be given to both the incremental operating and capital costs, in addition to an incentive which is reflective of a portion of reference price.
- Any incentive aimed at 'kick-starting' the development of a CBM industry should be made available prior to, or at, the exploratory stage.
- Where possible, work from current rules and regulations and modify where necessary to reflect CBM specific costs and other related variables.
- Any incentives established for crown lands be considered for application to freehold lands.

CBM Workshop

The Advisory Committee recommended that a workshop be organized in order to broaden the scope of stakeholder input toward prioritizing the CBM related issues, expanding on the Sub-Committee mitigation strategies or resolutions, and examining the pros and cons of each. The resulting workshop took place on June 13th in Calgary[8] with 108 registrants, representing 42 companies, seven government departments, and one non-government organization. Two guest speakers provided valuable background from the perspectives of producer and regulator. The objectives of the workshop were accomplished through the efforts of the participants during five breakout sessions. The highlights of the industry comments follow.

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[8] The facilities for the CBM Workshop were provided by PanCanadian Petroleum Limited.

Technical Breakout Session

Priority Issues

- data availability - lack of and need for harmonization;
- drilling requirements - CBM versus conventional;
- test site facility - data collection, foster education; and,
- production forecasting required to establish economics - working with an 'unknown science'.

Mitigation Strategies

- designation of 'CBM' wells by the EUB;
- regulatory change recognizing CBM uniqueness; and,
- baseline studies (i.e. water: both basin-wide and watershed; could involve Alberta Geological Survey, Geological Survey of Canada and industry).

Land Access and Tenure Breakout Session

Priority Issues

- separation of CBM against conventional petroleum and natural gas (P&NG) development;
- contiguity and size of land;
- surface access and costs;
- timing of agreements; and,
- data-sharing issues.

Mitigation Strategies

Interim Suggestions

- forced pooling (EUB – size of spacing units an issue);
- clear definitions for test well, experimental schemes;
- expansion of Deeper Rights Reversion Zone Designation (DRRZD) to include methane bearing coals and zone specific postings;
- flexibility on Section 17 - continuations for CBM pilot projects; and,
- forewarn the EUB of their role in resolving potential CBM-NG disputes.

Long-term Suggestions

- non-productive zone reversion;
- zone-specific leasing;
- CBM unitization (requires examination by both Alberta Energy and EUB);
- changing rules for continuations for CBM projects; and,
- clarity in definitions of zones (to avoid a "Surmont").

Water Disposal and Diversion Breakout Session

Priority Issues

- dewatering of non-saline aquifers is not allowed by AENV;
- surface discharge of non-saline water for CBM is not allowed by the EUB; as well, deep disposal of non-saline water is not allowed by AENV without specific approval; and,
- length of groundwater diversion process; notification key issue.

Mitigation Strategies

- policy change (AENV) to allow dewatering of coal seams for CBM projects; tie to an existing application process (one window approach through the EUB);
- EUB policy change to generally permit surface discharge, as allowed under *AEPEA*;
- combine or merge EUB/AENV processes; and,
- overall recommendation: baseline studies on a project by project basis funded or coordinated by Alberta Energy.

Non-Technical Breakout Session

Priority Issues

- window of opportunity (may be short…before Northern gas projects are announced);
- need for a competitive environment;
- access to information and confidentiality issues;
- public consultation required with all stakeholders including local governments and interest groups;
- need for research and development; and,
- need for a flexible and responsive process for regulatory change to address such issues as flaring, water and operational issues.

Mitigation Strategies

- industry to consider asking the EUB to review 'CBM Task Group'; and,
- research and development - a government role in baseline, non-site specific studies.

Economic Breakout Sessions

Priority Issues

- CBM specific costs - expectations of large upfront costs, high risk, long payout periods; and,
- large, contiguous land base required and the inability to post from the Crown.

Mitigation Strategies

- upfront credit for capital spending to offset other royalties (most favored);
- unique CBM capital recognition - carry forward capital; deferred royalty; negative royalty banking;
- reduced royalties;
- oil sands type of fiscal regime (Revenue - Cost); and,
- increased Gas Cost Allowance Asset Base.

Throughout the remainder of this report, the critical issues discussed herein will be further examined and elaborated upon through incorporation of lessons learned and experiences gained by stakeholders in several U.S. CBM basins.

IV. UNITED STATES BASIN EXPERIENCE

The development of the CBM industry in the U.S. has been influenced by a number of key events and factors. In the 1960s and 1970s, the U.S. Bureau of Mines conducted research into the degasification of coal seams in the interests of improving coalmine safety. Over the next decade the U.S. Department of Energy was formed which was responsible for the undertaking of numerous CBM research projects.

Perhaps the most significant event, however, was the introduction of the Section 29 Tax Credit (*see Appendix II*) in 1980, which was largely in response to the concern for energy supplies stemming from the 1973-74 Arab Oil Embargo. The Internal Revenue Code Section 29 provides a tax credit for production of certain non-conventional fuels, including gas from coal seams, if produced and sold before December 31, 2002 from a well drilled prior to 1993. The tax credit is currently around $1.00 per thousand cubic feet (mcf), reducing the regular tax liability, dollar-for-dollar.[9] Another major driving force to CBM development came out of the President's 1993 Climate Change Action Plan, whereby coalmine operators were encouraged to recover and use CBM.

Worldwide estimates of CBM supplies could be as high as 9000 trillion cubic feet (tcf). In the U.S., over 700 tcf [10]of natural gas is believed to be stored in the 14 coal basins indicated in Figure 6. The growth of CBM production in the U.S. has been dramatic. As indicated in Figure 7, production has grown from 91 billion cubic feet (bcf) in 1989 to currently over 1.2 tcf, which represents over 6 per cent of total U.S. natural gas production. Further, this is equivalent to 20 per cent of Canada's annual production (6.3 tcf in 2000)[11] or about one-third of the volumes exported to the U.S. (3.6 tcf in 2000).[12]

Continuing with the focus on the five key aspects of CBM development discussed in Section III, two U.S. field trips were taken to compare issues and mitigation processes developed from experiences of U.S. stakeholders (eight producers, six regulatory agencies, and one landowner) in selected CBM basins.

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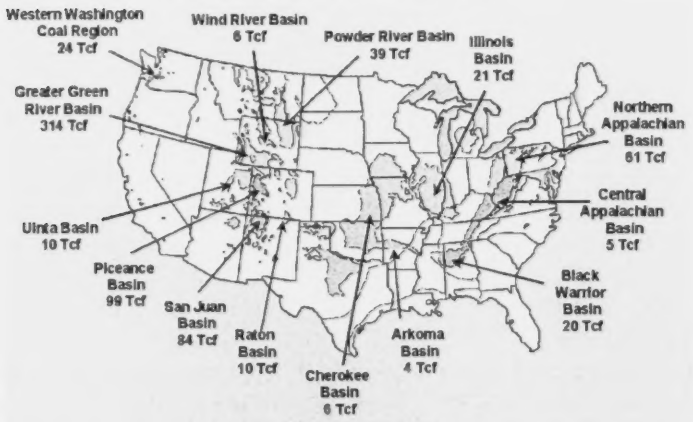
[9] Independent Petroleum Association of America, Fact Sheet, *Internal Revenue Code Section 29 Tax Credit Availability*, February 27, 2001.

[10] The first recorded well drilled in the U.S. was in West Virginia in 1931. San Juan, Colorado became the basin of interest in the 1950s, and although some success was achieved, it was not until 1977 when Amoco Production Company completed its first well in the San Juan Basin that the current generation of the CBM players came into being. (Source: Joseph Ayoub, Lief Colson, Jerry Hinkel, David Johnston, Jeffrey Levine, *Learning to Produce Coalbed Methane*, January 1991).

[11] Alberta Energy and Utilities Board, *Alberta's Reserves 2000 and Supply/Demand Outlook 2001-2010 Statistical Series 2001-98*, Alberta Energy and Utilities Board, Calgary, Alberta ISSN 1499-1179.

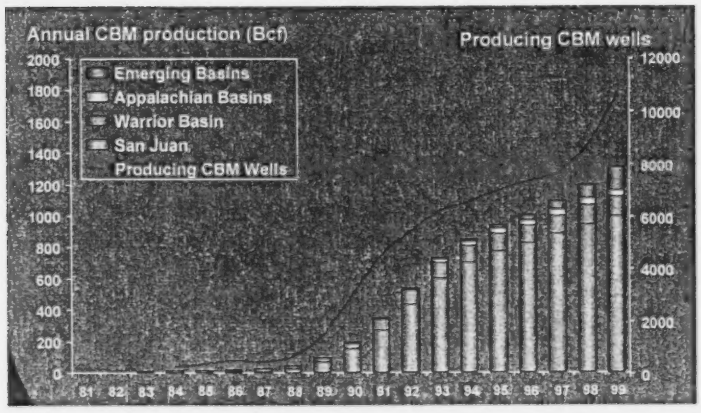
[12] National Energy Board website.

Figure 6
U.S. Lower-48 CBM Resources


Western Washington Coal Region 24 Tcf
Wind River Basin 6 Tcf
Powder River Basin 39 Tcf
Illinois Basin 21 Tcf
Greater Green River Basin 314 Tcf
Northern Appalachian Basin 61 Tcf
Central Appalachian Basin 5 Tcf
Uinta Basin 10 Tcf
Piceance Basin 99 Tcf
San Juan Basin 84 Tcf
Raton Basin 10 Tcf
Cherokee Basin 6 Tcf
Arkoma Basin 4 Tcf
Black Warrior Basin 20 Tcf

Source: Gas Technology Institute

Figure 7
U.S. Coal Bed Methane Production



Lessons Learned from U.S. Stakeholders

Technical Issues

The focus of the technical issues identified in the Alberta consultation process centered on the lack of CBM related data and the need for harmonization and dissemination of existing information. U.S. experience substantiates the importance of developing, collecting, consolidating, and continually analyzing the technical data required to ensure the optimal development of CBM in Alberta using the most appropriate drilling, completion and production technologies.

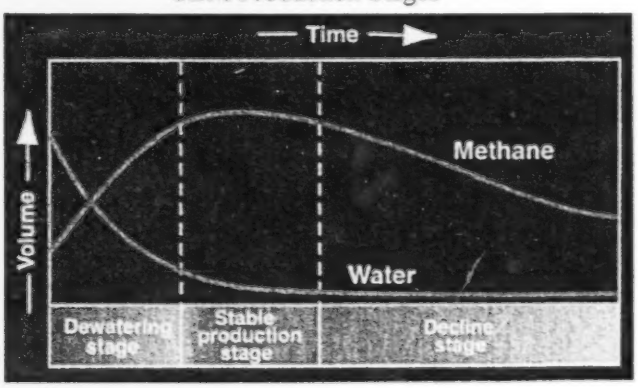
As stated at the outset, the amount of CBM generated and stored in coals is dependent upon the following geological criteria:

- coal rank;
- composition and quality;
- thickness of the seams;
- reservoir depth and thermal history; and,
- reservoir permeability.

Table 1 compares selected characteristics across several U.S. and Canadian CBM regions[13].

There are generally three stages to the production cycle of CBM wells as indicated in Figure 8. In the initial dewatering stage, the production of water typically exceeds the production of gas. As production continues and the reservoir becomes depressurized, gas production increases until it reaches a peak and water production declines and tends to stabilize. Finally, the production of CBM declines to a level, which makes continued production uneconomical.

Figure 8
CBM Production Stages



[13] Note that the drilling costs indicated reflect conventional CBM development and exploitation technologies.

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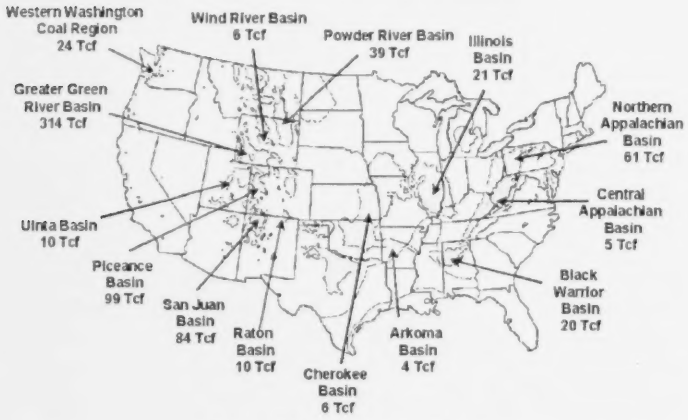
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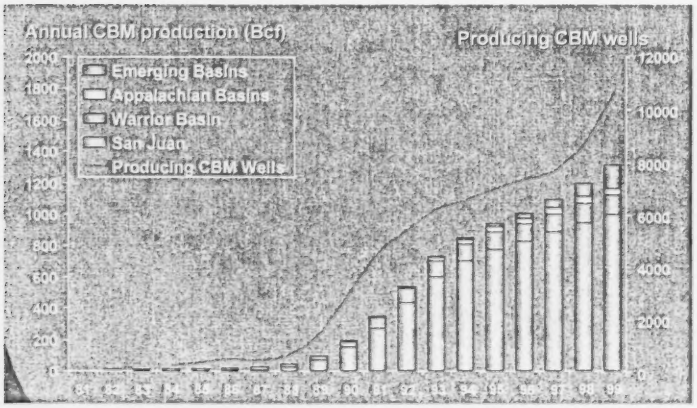

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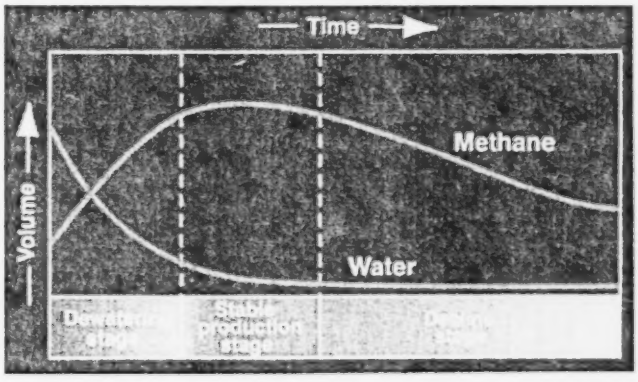

[13] Note that the drilling costs indicated reflect conventional CBM development and exploitation technologies.

Table 1
CBM Basin Characteristics

Basins/ Criteria	San Juan	Raton	Powder River	Warrior	Plains	Central	Foothills
Area	NM,CO	NM,CO	WY,MT	AL,MS	AB	AB	AB
Depth Metres Feet	 1,980 6,500	 1,200 4,000	 750 2,500	 1,200 4,000	 300-900 1000-3000	 900-3000 3000-10000	 200-1600 650-5000
Coal Thickness Metres Feet	 2.4-4.6 8-15	 .5-2 2-5	 1-30 3-100	 6-9 20-30	 5-15 16-50	 2-11 6-36	 2-15 6-50
Permeability (millidarcies)	< 50	< 10	< 1 D	< 30	0.1-10	.1-2	.1-5
Estimated CBM Resources (tcf gas-in-place)	84	10	39	20	350		60
Estimated Recoverable Reserves (tcf)	11.567	3.493	9.329	4.35	115		20
Gas Content (typical) cc/gram scf/ton	 13.4 430	 9.0 300	 0.9 30	 1.0 350	 2-4 64-128	 8-15 256-480	 8-20 256-640
Number of Producing Wells	3,100+	220	1,400	3000+	0	0	0
Spacing (acres)	320	160	40	80	N/A	N/A	N/A
Average Cost Per Well (C$)	540k	485k	85k	-	200k	300k	600k

Source: GTI Canada, MGV Energy Inc., Geological Survey of Canada, industry

The following examination of the San Juan and Powder River Basins is used to emphasize the importance of a solid understanding of the technical data and provides some of the lessons learned from these areas. *[See stages of CBM production, Appendix III]*

The San Juan Basin

The San Juan Basin, one of the richest deposits of natural gas in the U.S. and the leading CBM production area in the world, straddles northwest New Mexico and southwest Colorado, covering some 7500 square miles. Though it was recognized for many years that the Fruitland coalbeds contained significant reserves of CBM, the early developers did not have the understanding of the technology required to produce the reserves. As a result, CBM was overlooked in favor of conventional exploration and development. The Amoco 'Coal Degas' project, initiated in 1975, marks the beginning of the CBM industry as recognized today.[14]

[14] MGV Energy Inc. and gticanada, *Overview of Coalbed Methane*, 2000, p. 4-30.

The San Juan Basin is characterized by coals of the Cretaceous and Tertiary Age and range from sub-bituminous B to medium volatile bituminous. Typically they are between 30 and 80 feet thick, at depths between 1600 and 4000 feet, having permeabilities up to 50 millidarcies (md)[15] with gas contents ranging from 300 to 500 standard cubic feet (scf) per ton on well spacings of 320 acres. In the San Juan Basin, there are several separate production areas which require 'local tweaking' when it comes to determining the optimal drilling and completion techniques. The CBM is produced by one of two methods. One method involves a hydro-fracing process which pumps water and sand into the coal seams at high pressure and the other is a cavitation process in which a cavity is created in the coal seam (ranging from a few feet to 20 feet wide) by the repeated injection of air or water mist over typically one to three weeks.

In 1987, Meridian Oil Company[16] pioneered the Fruitland coalbed gas well open-hole cavity completion technique,[17] followed soon after by other producers once the production data from the initial Meridian wells became public. As indicated in Table 2, CBM wells in the Fruitland Formation drilled with open-hole cavities, using a controlled injection-blowout process, tend to produce much greater volumes of gas and water than cased hydraulically fractured wells. Specifically, the increased production resulting from the cavity completion process effectively links the wellbore with the natural fracture system of the coal reservoir.

The following comments shared by a major producer underscore the primary necessity to drill and experiment in order to understand the technical variances throughout any given basin. In the San Juan, some people recognize two distinct producing areas, the fairway and the non-fairway; others would suggest there are more. As indicated above, wells in the fairway, the over pressured area in the north half of the basin responds well to open-hole (or uncemented pre-perforated liners) cavitation completions that are essentially air fracs. This is probably due to a combination of several factors including stress, timing, and the over pressured environment. In the northeast part of the basin (Santa Rosa Unit), some wells respond to normal completions and 'slick water' fracs while others do not respond at all, despite the fact that from log analysis the coals appear to be the same. In La Plata County, Colorado, in the northwest region of the San Juan basin where a second fairway extends, the wells are less prolific than its New Mexico counterpart but respond well to both fracing and open-hole cavitations; New Mexico fairway wells do not seem to respond well to fracing. Also in La Plata County, to the east of the Colorado fairway is an area of lower rate wells that respond to fracs. Finally, south of the New Mexico fairway, lie the non-fairway coals which are completed as cased hole, perforated and fraced.

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[15] In a presentation by Devon Energy Corporation at the Alberta Department of Energy CBM Workshop on June 13, 2001, the range of permeability encountered in their projects in the San Juan Basin was noted as being between 250 and 500 md.

[16] Now Burlington Resources.

[17] Matt Mavor, Resource Enterprises, Inc. *Evaluation of Coalbed Natural Gas Open Hole Cavity Completion Productivity*, Coal and Coalbed Methane Forum, Parksville, British Columbia, February 1992.

Table 2. Northeast Blanco Unit Completion Productivity

Originally Cased & Fractured Wells		Re-Drilled Cavity Wells		Cavity/Cased Production Ratio	
Well Number	Initial Gas Rate	Well Number	Initial Gas Rate	Stable Gas Rate	Initial
	m^3/d		m^3/d	m^3/d	-
400	3,100	400R	73,600	?	23.6
403	28,000	403R	309,000	147,000	10.9
404	4,200	404R	640,000	184,000	150.0
413	11,000	413R	306,000	93,400	27.8
421	23,000	421R	648,000	184,000	28.6
423	6,800	423R	283,000	119,000	41.7
425	7,900	425R	374,000	76,500	101.7
427	24,000	427R	252,000	56,600	10.3
429	13,000	429R	56,600	25,500	4.3
441	20,000	441R	19,800	14,200	1.0
Total	142,000	Total	2,962,000		20.8

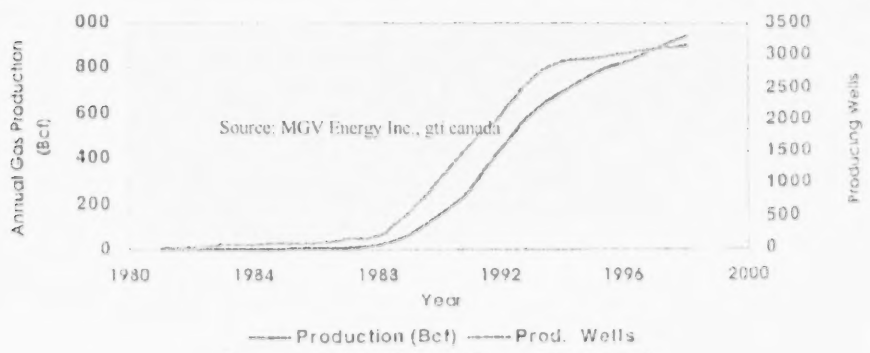
Source: Matt Mavor, *Evaluation of Coalbed Natural Gas Open Hole Cavity Completion Productivity*, February, 1992.

The important lessons shared by this producer are the following:

- Local knowledge and design of completions that build on prior knowledge and experience is required to know what works…and works well.
- This knowledge is particularly important for small operators with limited resources.
- At the end of the day, shared information on successful and failed experiments is the best way to advance the local knowledge required for successful CBM completions.

The combination of a better understanding of the technical characteristics of the San Juan Basin and the impact of the Section 29 Tax Credit, which spurred drilling programs in the late 1980s and early 1990s, resulted in a major jump in the production of CBM as indicated in Figure 9, along with an increase in estimated reserves. *[See Appendix II]*

Figure 9
San Juan Basin Coalbed Methane Annual Production and Producing Well Count



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413	11,000	413R	306,000	93,400	27.8
421	23,000	421R	648,000	184,000	28.6
423	6,800	423R	283,000	119,000	41.7
425	7,900	425R	374,000	76,500	101.7
427	24,000	427R	252,000	56,600	10.3
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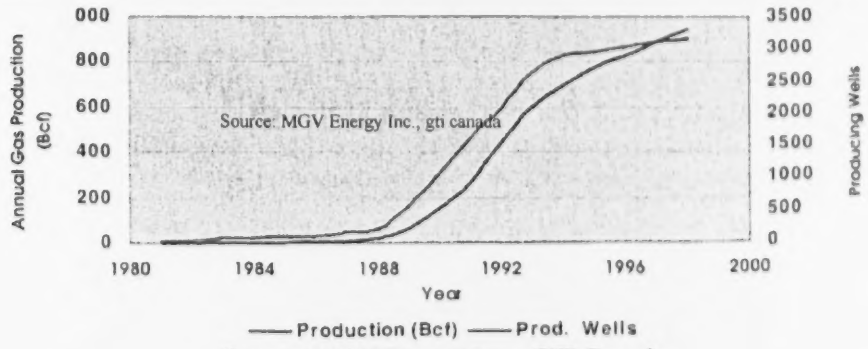

Source: MGV Energy Inc., GTI Canada

The Powder River Basin

The Powder River Basin offers a significant contrast to the San Juan Basin CBM development. The Powder River Basin, some 25,000 square miles in area, straddles the Wyoming/Montana border, with the majority of the basin lying within the northeastern region of Wyoming [*See Appendix IV*]. The coals are typically of the Paleocene stage of the Tertiary and Cretaceous periods.

Bituminous and sub-bituminous coal beds, containing both biogenic and thermogenic CBM, are found in all 10 coalfields of Wyoming. Much of the drilling in the Powder River has been focused in the relatively shallow, thick coal beds containing large quantities of biogenic CBM. These coals have typically been around 80 feet thick, at depths of 1000 feet, containing 30 to 75 scf/ton of gas, with permeabilities ranging from 250 to greater than 1000 millidarcies[18]. Spacing units in the basin are one well per 40 acres. Though not the current focus, it should be noted that Cretaceous and some Tertiary coal beds, found in many deep Wyoming basins, are much more thermally mature and are presumed to contain significant volumes of thermogenic gas.[19]

Wells are drilled relatively cheaply with truck-mounted rigs using air, air-mist, or water and are completed open-hole. As shown in Figure 10, a casing is set to the top of the target coal bed with the underlying zone being under-reamed and cleaned out using a fresh-water flush. Water is produced using a down-hole submersible pump; gas is separated from the water and is produced up the annulus.

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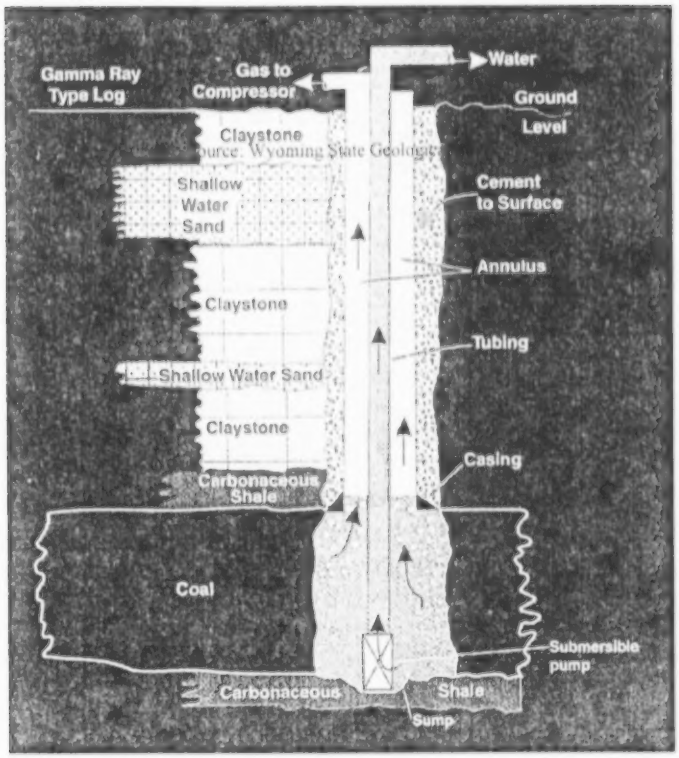
[18] Rick White, Devon Energy Corporation, "The Successful Environment for CBM Development in Alberta", presentation to the Alberta Department of Energy CBM Workshop in Calgary on June 13, 2001.
[19] Rodney H. De Bruin, Robert M. Lyman, Richard W. Jones, and Lance W. Cook, *Coalbed Methane in Wyoming*, Information Pamphlet 7 (revised), Wyoming State Geological Survey, Laramie, Wyoming, 2001.

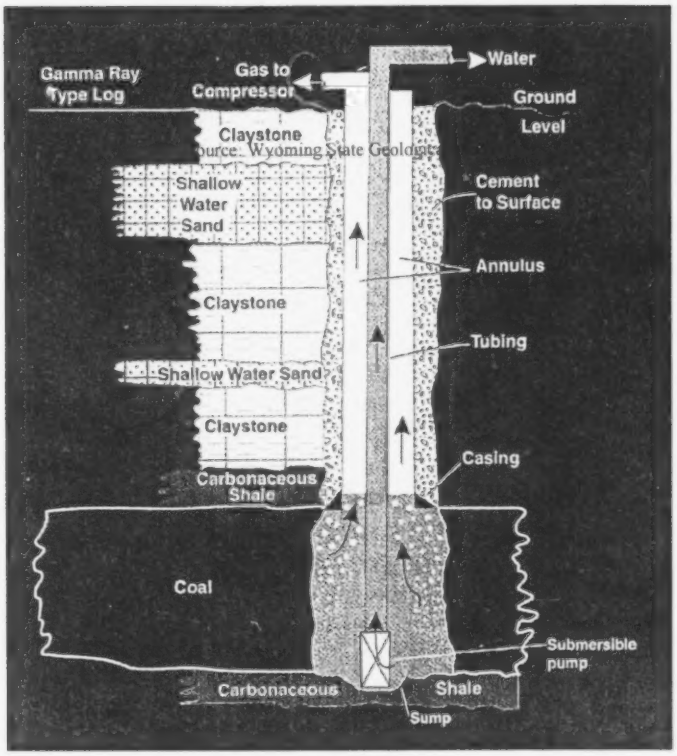
Figure 10
Open-hole Completion Technique



Development of CBM in the Powder River Basin is a classic stop and restart scenario. Although CBM has been recognized in water wells since the 1950's, by 1987 annual production levels had only reached 0.1 bcf. The Powder River coal beds are not well documented and have been relatively unexplored. To the early producers, it appeared that much of the coal was either too deep or not of sufficient thickness to prove economically viable. It was only after the industry gained sufficient technical knowledge that reconsideration of the Powder River Basin received renewed focus. Figures 11 and 12 show the explosive growth in both numbers of wells drilled and annual production since 1993. Well numbers are increasing at a rate of 11 drilled per day with the average well producing 120 mcf/day and 260 barrels of water per day (bbl/d); the average CBM production has increased by 96 per cent per year.[20] It is important to note that wells included under the Section 29 Tax Credit had to be drilled prior to 1993. In other words, Section 29 was not the driving force behind the surge in Powder River CBM development; rather it was the increased understanding and knowledge of the coal and reservoir characteristics.

[20] Information provided by Don Likwartz, Oil & Gas Supervisor, State of Wyoming, Oil & Gas Conservation Commission.

Figure 10
Open-hole Completion Technique



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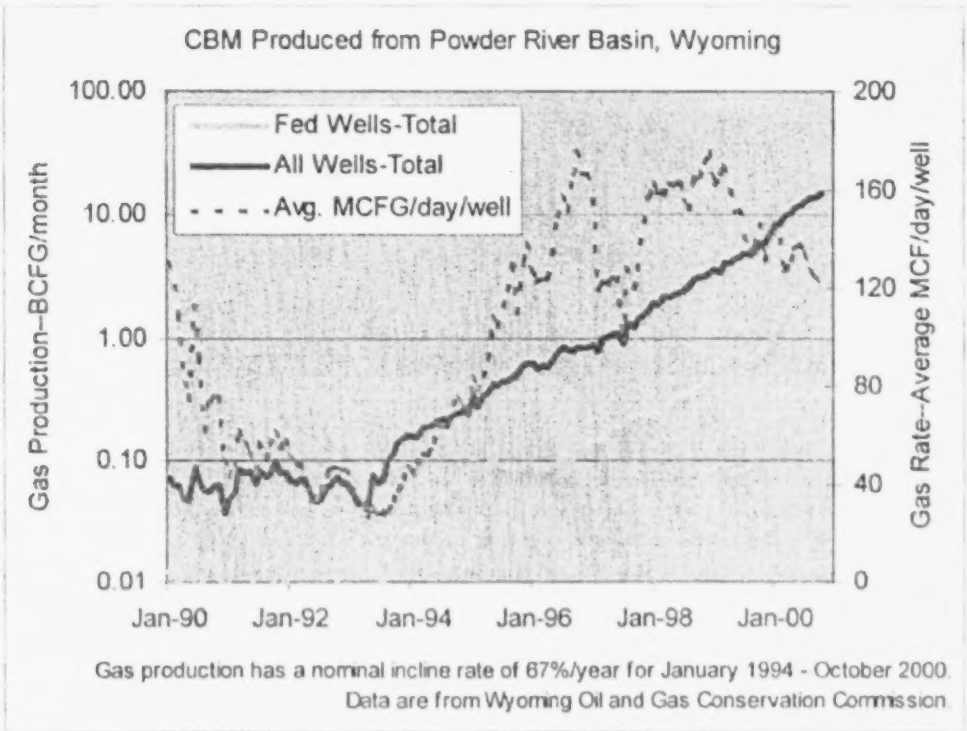
[20] Information provided by Don Likwartz, Oil & Gas Supervisor, State of Wyoming, Oil & Gas Conservation Commission.

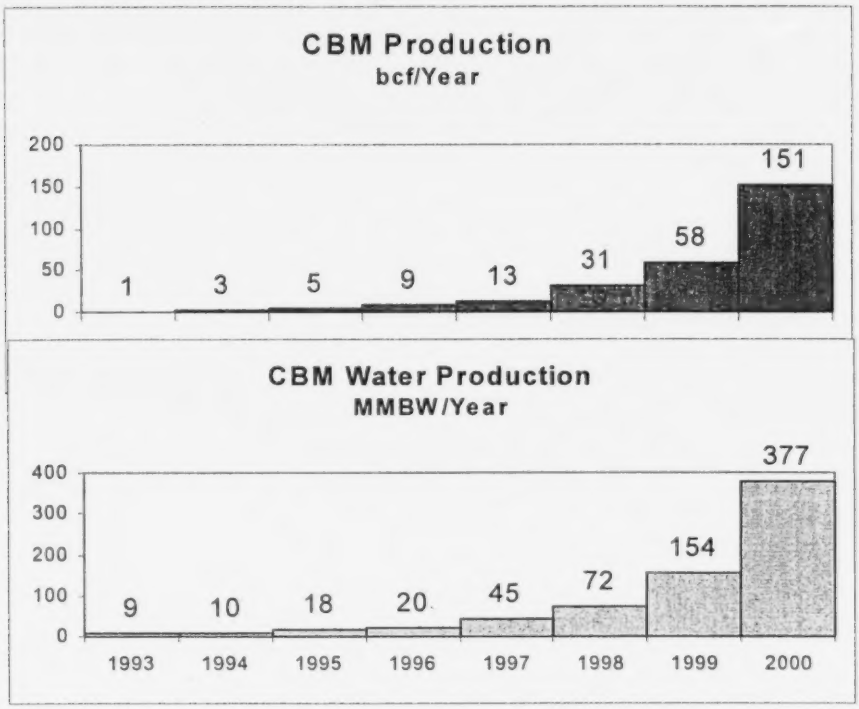
In 1999, the need was recognized to obtain more accurate gas content and gas-in-place estimates. The U.S. Bureau of Land Management (BLM) (Wyoming Reservoir Management Group) and the U.S. Geological Survey (USGS) (Central Energy Resources Team) initiated a cooperative project to gather technical data, primarily from coal cores provided by cooperating CBM operators, to analyze and evaluate the CBM resources and reservoirs in the Powder River Basin. The two agencies share complementary, but slightly different goals, information needs, and mission statements. Further, this project is designed to address the public need for data as it relates to Powder River Basin CBM resources.[21]

Figure 11



[21] Romeo M. Flores, Gary D. Stricker, Joseph F. Meyer, Thomas Doll, Pierce H. Norton, Jr., Robert J. Livingston, and M. Craig Jennings, *A Field Conference on Impacts of Coalbed Methane Development in the Powder River Basin, Wyoming*, Open-File Report 01-126, U.S. Geological Survey, Denver, Colorado, 2001, p. 2.

Figure 12



Source: Wyoming Oil and Gas Conservation Commission

It is equally important to note that in all U.S. CBM basins, cumulative production has far exceeded initial projections and continues to increase. For example, in August 2000, the estimated reserves of CBM in the Wyoming portion of the Powder River Basin soared to 25 tcf, surpassing estimates of only 9 to 12 tcf just a few years prior. This positive increase was the direct result of the assessment of data developed through the drilling of some 8,600 wells.[22]

Technical Mitigation Strategies

Relating the above experiences back to the focus of the potential for CBM development in Alberta, namely the Plains and Foothills regions, it should be recognized that:

- no two basins are technically the same; and,
- there is no substitution for drilling, continuous research and data analysis, and the public dissemination of this knowledge in order to resolve the technical barriers and identify the optimal completion and production technologies (balanced with the appropriate consideration for confidentiality).

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[22] Lance Cook, State Geologist, Wyoming State Geological Survey, *Coalbed Methane Reserve Revision*, August 3, 2000. According to this public release, previous estimates of recoverable gas have suggested a recoverable resource ranging from 9-12 tcf. The release goes on to say that these previous estimates were based upon very superficial analysis, utilizing limited data.

Land Access and Tenure Issues

The Alberta survey and consultation process identified a number of land access and tenure issues such as contiguity and size of land tracts, surface access and costs, resource ownership and well spacing.

The CBM industry in the U.S. extends well over 20 years, with the development of some basins being more mature than others. Over this time, for the most part, the challenge of assembling large, contiguous tracts of land, and related costs has been solved in the marketplace. In addition, the question of resource ownership on U.S. sovereign lands, as with Alberta Crown lands,[23] has seen resolve. Precedence was set in the June 7, 1999 decision by the United States Supreme Court (Amoco Production Company versus Southern Ute Indian Tribe) wherein the court concluded that "the most natural interpretation of "coal" did not encompass "coalbed methane" therefore, on sovereign lands, it is not the owners of the coal who own the CBM. The decision, however, was not determinative in addressing the situation as it relates to 'private' lands, an outstanding issue in Alberta as well. Further, the U.S. decision did not give effect to the 'custom of the industry', which assumes that had liability been suffered due to the presence of CBM, then liability would accrue against the non-coal owner.[24]

A key question related to CBM projects is the space required between wells to achieve the required pressure interference. Ultimately, U.S. experience suggests that the developer should rely on the science of the reservoir to define the optimal spacing units so as not to over-invest relative to the recoverable reserves.

As indicated in Table 1, the current well spacing requirements vary across the U.S. basins. Well spacing is currently under review in the San Juan Basin. The Colorado Oil and Gas Conservation Commission (COGCC) establishes gas well spacing orders through a public hearing process. The U.S. BLM then reviews these orders, which, of note, are not binding on tribal lands without BLM concurrence. Well spacings in the Colorado portion of the San Juan Basin were limited to 320 acres until 1992 when, on certain 320-acre units, two wells were allowed for optimum spacing and gas recovery. This served as a test of the reservoir simulation studies, which suggested that 160-acre spacings would be optimal for overall reservoir performance, economics and accelerated recovery of additional reserves that might otherwise be left unrecovered.

It should be noted that, while the Southern Ute Indian Tribe and the BLM supported this proposal as put forward by Emerald Gas Operating Company as a pilot project, some operators, the COGCC, and some members of the general public actually opposed the

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[23] As outlined in Informational Letter IL 91-11 (see Appendix I), in Alberta the right to Crown natural gas is governed by the Mines and Minerals Act in which natural gas and coal are treated as distinct substances and are leased separately. The Act does not consider a coal lessee as having any right to the gas except when, on the recommendation of the Energy Resources Conservation Board (now the Alberta Energy and Utilities Board) the coal lessee is authorized to recover the CBM due to safety or conservation reasons.

[24] Michael J. Laffin, Partner Drummond Phillips & Sevalrud, *Legal Considerations in the Development of Coalbed Methane*, The Canadian Petroleum Law Foundation, Annual Research Seminar in Oil and Gas Law, June 2, 2000.

project, stating that the 320 acre spacing was adequate, correlative rights would be affected, and that it could set a precedence for basin-wide down-spacing. Following this precedence, some 60 infill wells were approved and completed by the end of 1998. Based on results, industry is now seeking approval for similar well spacing throughout most of the northern San Juan Basin.[25] It has been suggested by the COGCC that if producers and regulators see sufficient economic merit and legal justification to continue allowing optional infill wells on the existing 320-acre spacings, between 550 and 1000 CBM wells may yet be drilled in this region.

In the Powder River Basin, the issue and determination of well spacing regulations has followed a somewhat different process. Initially, the statutory spacing requirement was set at one well per 40 acres. With progressive development, operators have determined that the reservoir characteristics allow for optimal drainage using one well per 80 acre spacing. After 120 spacing hearings, regulators revised the rules in July 2000 allowing for two wells per 160 acres in the Powder River Basin in the northeast and southwest quarters, with exclusions applying to 12 Federal Units, 24 'spaced areas' and 19 of 385 townships in the fairway.[26]

The issues of unit agreements, communitization agreements and compensatory agreements in the Wyodak Drainage Area within the Powder River Basin are currently under review due to the concern of the BLM that the existing CBM wells are not meeting their objective of maximum economic recovery. The BLM felt the need to conduct an analysis due to the disparity between the number of state and private CBM wells being permitted, drilled, and put into production when compared to the number of federal wells. One of the solutions put forward by the BLM included the following comments with respect to unit agreements. "A unit agreement is a contract between the federal government and the interest owners of federal, private and state leases in an area with potential oil and gas resources. This includes owners of any right, title, or interest in the oil and gas deposits to be unitized. The actual producers may or may not fit this definition. Unitization is intended to facilitate the orderly and timely development of all the oil and gas resources within the proposed unit area. The BLM encourages federal unit agreements be established whenever and wherever practical. To date, 24 federal units have been approved. However, the BLM cannot force a private or state interest owner to enter into a unit agreement contract. Since the vast majority of the CBM wells have been drilled on, and are producing from, non-federal lands, there is little to no incentive for the interest owners of the non-federal leases to enter into a unit agreement."[27]

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[25] Bureau of Land Management (San Juan Field Office), San Juan National Forest, *Coal Bed Methane Development in the Northern San Juan Basin of Colorado* (For Supporting Documentation, see Coal Bed Methane Development in the Northern San Juan Basin of Colorado "A Brief History and Environmental Observations; A Working Document", as amended March, 2000) **www.co.blm.gov/sjra/sjra.html**, p.5.

[26] Background notes prepared for the Governor's CBM Tour, June 8, 2001 by Don Likwartz, Oil & Gas Supervisor, State of Wyoming, Oil & Gas Conservation Commission.

[27] U.S. Bureau of Land Management, Wyoming State Office, Decision Record, *Wyodak Drainage Coal Bed Methane Environmental Assessment* (WY-070-01-034), March 2001, p.12.

Land Access and Tenure Mitigation Strategies

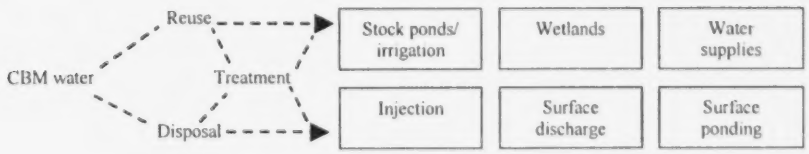
Lessons gathered and shared by stakeholders in the San Juan and Powder River Basins relative to land issues include the following:

- The challenge of assembling the required large contiguous land bases[28] for exploration and development of CBM has been resolved in the marketplace. Due to the extensive history of the conventional gas industry in Alberta, relative to some of the newer U.S. CBM play areas, this issue may be more complex because of the existing land tenure system, in particular, and the way CBM rights can be retained by production from other zones.
- Ownership of the CBM on 'private lands' remains an outstanding issue in both the U.S. and Alberta.
- Well spacing requirements in the U.S. CBM basins continue to be reviewed and revised as greater and more accurate data is accumulated from drilling experience. In Alberta, current spacing requirements are one well per section, which, according to U.S. stakeholders, will not suffice for optimal development of the province's CBM resources; flexibility, reflecting the science of the reservoirs will be required.
- Further review is required of the long-term benefits and implications of unitization.

Water Disposal and Diversion Issues

CBM production is normally associated with the production of significant volumes of water, which must be removed in order to depressurize the coal beds and allow the natural gas to flow. From U.S. experience, this inherent process has lead to a number of critical technical, economic and environmental issues surrounding the question of how best to handle the produced water. As indicated in Figure 13, the most common disposal/diversion options considered are discharge to the watershed (rivers, streams, ponds, lakes, wetlands); discharge to evaporation ponds; deep well injection; and injection to or recharging of groundwater aquifers.

Figure 13
Water Disposal/Diversion Options



Source: U.S. Geological Survey

[28] The U.S. producers interviewed suggested land bases of 20,000 to 50,000 acres were preferable for CBM projects, for economic and competitive reasons.

The volume of water produced, its characteristics and the ratio between water and gas production varies throughout the U.S. CBM basins. The variation is based upon several key factors including the original depositional environment of the coal beds, the characteristics of the coal, and over what timeframe CBM has been produced from the basin. Recent regulatory changes governing withdrawal and disposal of water have resulted in more extensive and accurate water data related to both the volumes produced and composition. (See Tables 3 and 4)

Table 3. Average Water Composition

Uinta Basin (Ferron CBM, Utah) 1 mg/l				
Field	**TDS**	**Cl**	**HCO_3**	**Br/Cl**
Buzzard Bench	11000	2300	8500	0.0083
Drunkards Wash	8900	2500	5500	0.0032
Helper State	25000	14000	5200	0.0013

Table 4

Powder River Basin (Wyoming) 2					
	ug/L			ug/L	
	CBM	DWS		CBM	DWS
Arsenic	<3	50	Manganese	32	50
Barium	620	2000	Mercury	<0.3	2
Chromium	<2	100	Selenium	<2	50

Note: Concentrations of selected components in CBM water from three fields in the Ferron CBM area, Utah, and from 47 wells in Wyoming, TDS, total dissolved solids; DWS, drinking water standards Br (bromide) Cl (chloride) HCO_3 (bicarbonate). 1, Rice (1999); 2, Rice (2000).
Source: U.S. Geological Survey, *Water Produced with Coal-Bed Methane*, USGS Fact Sheet FS-156-00

Across the CBM basins, diverse options are in use. In the San Juan Basin, for the most part, the water is brackish and is required to be either corralled into an evaporative pond or reinjected. In the Warrior Basin, which covers west central Alabama and east central Mississippi, CBM water is pumped directly into the Black Warrior River. In Alabama, discharge of produced water from CBM wells is allowed into water systems under a National Pollutant Discharge Elimination System permit.[29] This permit environmentally regulates coalbed gas production as a mining operation, as opposed to a gas extraction operation. In the Powder River Basin, most of the water produced from CBM operations is permitted to be discharged at the surface as it generally meets Wyoming drinking water standards.[30] However, the water quality varies greatly throughout the basin and some

[29] Gas Research Institute, *Coalbed Methane: GRI Changes the Way Industry Does Business in Alabama*, 1994.
[30] Rodney H. De Bruin, Robert M. Lyman, Richard W. Jones, and Lance W. Cook, *Coalbed Methane in Wyoming*, Information Pamphlet 7 (revised), Wyoming State Geological Survey, Laramie, Wyoming, 2001.

CBM water is now being handled through reinjection into the source, or nearby aquifers. By comparison, in the Raton Basin, which straddles the eastern border between New Mexico and Colorado, surface discharge, evaporative ponds, and deep well injection are all utilized for the disposal/diversion of water.

From a technical and economic standpoint, there is the sheer physical challenge of handling the massive volumes of water, which can be produced with CBM, and the associated costs. As an example of cumulative water production, the northern San Juan Basin has produced approximately 250 million barrels of water since CBM production began. While the majority of this volume (removed from the basin interior) is brackish, about a quarter of the water has come from fresh water zones in close contact with surface outcrops.[31] From an economic perspective, producers in the San Juan noted that surface discharge was obviously the most simple and inexpensive water diversion option. Evaporative ponds, which require a double lining and significant monitoring equipment would be significantly more costly; if reverse osmosis and truck transportation are required, the resulting costs were in the two-dollar plus range per barrel. Deep injection is the primary disposal option in the San Juan; the price of each injection well was noted as around one to two million dollars, which translates to disposal, costs of 10 to 25 cents per mcf.

The development of a CBM industry has also raised a number of environmental issues and concerns. The primary concern tends to relate to the withdrawal of groundwater from aquifers, which are extensively used by landowners as 'beneficial use' water for both livestock and irrigation. Further, drawdown of groundwater also impacts the coal mining industry by reducing the amount of water available for required use in mining operations. In the Powder River, where CBM wells must be permitted as both gas and water wells, operators require permits from the Wyoming Oil & Gas Conservation Commission (WOGCC) as well as the Wyoming State Engineer's Office, with water discharges being permitted by the Wyoming Department of Environmental Quality (WDEQ). The basis for determining Wyoming's water quality standards for drinking water is defined by the Federal Safe Drinking Act and Environmental Protection Agency (EPA). For other surface water use (aquatic life, agriculture and irrigation, recreation), standards for protection are based on the Clean Water Act and EPA guidelines.[32] In practice, CBM producers generally cooperate with the landowners to ensure the co-produced water is diverted into either stock tanks or other holding areas for use by their livestock.[33]

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[31] Bureau of Land Management (San Juan Field Office), San Juan National Forest, *Coal Bed Methane Development in the Northern San Juan Basin of Colorado* (For Supporting Documentation, see Coal Bed Methane Development in the Northern San Juan Basin of Colorado "A Brief History and Environmental Observations; A Working Document", as amended March, 2000) **www.co.blm.gov/sjra/sjra.html**, p.12.

[32] Powder River Information Council, website: www.cbmwyo.org.

[33] Romeo M. Flores, Gary D. Stricker, Joseph F. Meyer, Thomas Doll, Pierce H. Norton, Jr., Robert J. Livingston, and M. Craig Jennings, *A Field Conference on Impacts of Coalbed Methane Development in the Powder River Basin, Wyoming*, Open-File Report 01-126, U.S. Geological Survey, Denver, Colorado, 2001, p.14.

Another major impact of CBM development is the effect of surface disposal on watersheds and the surrounding soil. Again, using the Powder River Basin as an example, it has been noted that surface disposal can result in erosion or drowning of drainage draws and associated vegetation. For this reason, some of the producers have been experimenting with reinjection technologies and one company, Pennaco Energy, is now reinjecting water into an aquifer used by the city of Gillette, Wyoming.[34] However, a current issue of note exists between Wyoming and Montana. A protest has been submitted to the WDEQ by the Montana Department of Environmental Quality claiming that CBM water production being discharged into the tributaries of the Powder River could adversely affect downstream water quality in Montana. In turn, the protest suggests potential adverse impacts on lands irrigated with this water in Montana.[35]

Gas migration into existing aquifers is a related issue of concern. For instance, in the northern San Juan Basin cooperative testing by the BLM and the Colorado Oil and Gas Conservation Commission has examined 10 per cent of the 6000 domestic water wells in the area and 80 per cent were found to have measurable methane content, many of which were of low concentrations. Concentrations of methane in the groundwater in this area are considered a concern if they exceed 1.1 milligrams per litre. The origin of the leakage is important. While the outside of the casing in CBM wells must be cemented from the surface to formation, this was not required for conventional gas wells prior to 1988. As a result, some conventional gas wells were not fully cemented through shallower coalbed seams.[36] The current problem is the result, therefore, of the extraction of water from CBM production where an older, inadequately cemented conventional wellbore is nearby. Similar concerns exist in other U.S. CBM producing basins such as the Black Warrior in Alabama where a legal dispute related to well water quality has been ongoing since 1989 (McMillan family/Legal Environmental Assistance Foundation, Inc. versus both state and federal agencies).[37]

Another primary concern is for the effect that the CBM co-produced water composition can have on soils. The Sodium Absorption Ratio (SAR) is a measurement, which compares the amount of sodium in the water against the amount of calcium and magnesium and is a measure of the tendency of sodium to replace other cations in clays in the soil, potentially reducing soil permeability. Generally high SAR values indicate potential problems with agricultural applications and clay rich soils are more susceptible to damage from high SAR values than are sandy, loamy soils. Shallower coals tend to have lower SAR values than deeper coals at any given location. Of note, SAR values can

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[34] Ibid., p. 14.

[35] Bureau of Land Management, Wyoming State Office, *Decision Record, Wyodak Drainage Coal Bed Methane Environmental Assessment (WY-070-01-034)*, March 2001, p.4.

[36] Bureau of Land Management (San Juan Field Office), San Juan National Forest, *Coal Bed Methane Development in the Northern San Juan Basin of Colorado* (For Supporting Documentation, see Coal Bed Methane Development in the Northern San Juan Basin of Colorado "A Brief History and Environmental Observations; A Working Document", as amended March, 2000) **www.co.blm.gov/sjra/sjra.html**, p.10.

[37] Sean Reilly, Washington Bureau, Mobile Register, *Methane Boom Raises Concern for the Environment*, August 23, 2000.

vary greatly across a CBM basin (for example, within the Powder River Basin, SAR values range from 3 to 60) necessitating the ongoing need for sampling and analysis.[38]

Water Disposal and Diversion Mitigation Strategies

Water issues have been described by many of the U.S. stakeholders as being the single most important issue surrounding the development of CBM resources because of the associated costs and environmental implications. It is critical, therefore, that water resource planning proceed in sync with land use planning and that an orderly direction and adaptive management process be followed. There is also a need for clarity and cooperation across jurisdictions and state and federal agencies (for example, in the definition of the 'beneficial use' of water). In many of the basins, regulatory agencies have been somewhat caught off guard by the growth and magnitude of CBM development so have had to respond reactively rather than proactively…the 'unknown' has played against CBM stakeholders.

Some have suggested the importance of a more holistic approach…'go slow to go fast'.[39] Included in such an approach could be a general permit concept (that takes into consideration existing rights of way, CBM implications and outfalls, and built-in feedback loops) and greater leniency with respect to pilot projects by allowing the rules to be adjusted or bent with the expectation of the data in return.

The need for baseline studies cannot be overstated. Regulators and industry emphasized the need for upfront, yardstick data as opposed to trying to resolve arising issues with insufficient background information. An example of a cooperative effort aimed at developing substantiated data for better managing CBM production and addressing environmental concerns is the '3M' Project. The BLM, Forest Service, Colorado Oil and Gas Conservation Commission, Southern Ute Indian Tribe, La Plata County, and industry have worked together over the past seven years on a comprehensive study which includes: Mapping of the Fruitland basin's surface and subsurface coal seams; Monitoring of water and reservoir pressures in the coal seams; and, hydrologic and reservoir computer Modeling of the Fruitland formation. It is anticipated that the results of the '3M' Project, expected to continue for another ten years, will address "concerns about increased gas seepage and the potential for depletion of surface waters as a result of CBM production."[40]

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[38] Rodney H. De Bruin, Robert M. Lyman, Richard W. Jones, and Lance W. Cook, *Coalbed Methane in Wyoming*, Information Pamphlet 7 (revised), Wyoming State Geological Survey, Laramie, Wyoming, 2001.

[39] Discussions with Marc Smith, Independent Petroleum Association of Mountain States and Gerald Jacob, Evergreen Resources Inc., Denver, Colorado.

[40] Bureau of Land Management (San Juan Field Office), San Juan National Forest, *Coal Bed Methane Development in the Northern San Juan Basin of Colorado* (For Supporting Documentation, see Coal Bed Methane Development in the Northern San Juan Basin of Colorado "A Brief History and Environmental Observations; A Working Document", as amended March, 2000) **www.co.blm.gov/sjra/sjra.html**, p.11.

Non-technical Issues

Non-technical issues cover a broad scope of areas including: access to information and confidentiality issues; the need for cooperation and public consultation; research and development; health, safety and environment; power requirements; and other societal issues.

Given the more advanced state of the CBM industry in the U.S., the issues of access to information and confidentiality of such are typically of less concern. For instance, in New Mexico, a producer has 20 days to file a completion report, which becomes public 90 days hence. Any logs on file are divulged along with forms submitted and the completion report. For example, the type of technology used (i.e., coil tubing) is not considered a competitive issue and thus is not kept confidential. Industry is working in a well-developed basin where most companies know what is going on.[41]

Considerable effort is underway to enhance cooperation and the public consultation process (one of the suggested mitigation strategies identified during the Alberta Energy CBM Workshop). Examples of multi-stakeholder initiatives include:

- A CBM Work Group has been formed in Wyoming which includes all related state agencies: Department of Agriculture, State Historical Preservation Office, Oil & Gas Commission, State Geological Survey, State Engineer's Office, Department of Environmental Quality, Wyoming Water Development Commission, Minerals Leasing & Royalty Compliances Division, and Wyoming Game and Fish…to promote better understanding among stakeholders and ensure consistency in response.[42]
- The CBM Coordination Coalition in Wyoming, jointly funded by industry and government, was formed to promote the 3 C's…coordination, communication, and cooperation.[43]
- An interagency group that includes Wyoming, Montana and Colorado was created to better understand what other agencies are doing on an ongoing basis (for example, Forest, Fish & Wildlife, National Parks, Environmental Protection Agency, etc.).[44]
- A Memorandum of Understanding (MOU) between the Colorado Bureau of Land Management and the Colorado Oil and Gas Conservation Commission was executed and contains the following:

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[41] Discussions with Steve Hayden, District Geologist, Deputy Oil & Gas Inspector, Energy, Minerals & Natural Resources Department, State of New Mexico.

[42] Discussions with Don Likwartz, Oil & Gas Supervisor, State of Wyoming, Oil & Gas Conservation Commission and Lynn Rust, Geologist/Minerals Analyst, Bureau of Land Management, Wyoming State Office.

[43] Discussions with Lynn Rust, Geologist/Minerals Analyst, Bureau of Land Management, Wyoming State Office, www.cbmcc.vcn.com.

[44] Discussions with the BLM and Colorado Oil and Gas Conservation Commission, Denver, Colorado.

a. Introduction
   For many years there has been a spirit of cooperation, communication and trust between the Colorado Oil and Gas Conservation Commission (COGCC) and the Colorado Bureau of Land Management (BLM) in the management of lands in the state of Colorado and the development of our nation's oil and gas resources. Each agency's mission and staffing levels have grown during these years to the point where we believe it is important to formalize our excellent working relationship, as well as define each agency's role and responsibilities in our overlapping jurisdictions.
b. Purpose
   Most of our operations occur on adjacent lands or on the same lands, and it is important that both agencies provide oil and gas lessee/operators with consistent policy and procedures (including statewide oil and gas orders) on federal/Indian lands as well as nonfederal lands.
c. Objectives
   This MOU between the Colorado BLM and the COGCC is intended to (1) avoid duplication of effort by the responsible oil and gas permitting agencies and (2) clearly define "jurisdictional authority."[45]

Another important vehicle used to improve communications, particularly with the general public, is that of trade fairs. Such events have been extremely successful. In Wyoming, five CBM trade fairs have been organized by a consortium of stakeholders and funded by the operators and service companies. All related government divisions had booths and provided speakers to better communicate their roles in CBM development with both industry and the general public. Attendance and participation, since inception, has grown from 200 to over 1500 attendees.

In one of the discussions with a group of state and federal stakeholders in Colorado, it was noted that there could be significant benefits to the appointment of an ombudsman to 'steer the ship' regarding energy and environmental related issues and act as an advocate by supporting positive, sustainable CBM development.

Landowners are a very critical stakeholder in the overall CBM development process. Following are a number of thoughts for consideration as expressed by a landowner in Price, Utah, who has been associated with CBM development for many years as both a landowner and as a service company operator.[46]

In responding to the question of what he would ask of a producer wanting to operate on his land, his comments included the following:

What are the development plans of the CBM operator, in particular, details about the well sites, roads and pipelines? In his experience, he found that if details were not addressed in an overall plan, companies tended 'to wing it'. This resulted, in one instance, of a

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[45] Referenced from **www.oil-gas.state.co.us**.
[46] Discussions with Jerry J. Jensen, Tri-J Services, LLC, Price, Utah.

location being built in violation of existing spacing orders and therefore will never be drilled. Timing of road construction is critical to a landowner; in his case, some roads were roughed in during the spring snowmelt, which resulted in extensive surface damage.

What are the company's plans for water handling? If you deal with the water properly for the given area, he noted, a successful project should result, all else being equal.

Does the company have the financial capability 'to undertake and complete' a CBM project? It has been his experience that companies often spend a lot of money on the wrong things as they think it is cheaper than doing the right things. Any lack of financial commitment to a project can lead to a stop and start scenario, which is both undesirable from a landowner's perspective and must be uneconomic from the producer's standpoint.

Open communication and understanding, particularly between operators and landowners, was underlined repeatedly over the course of the U.S. field trips as essential for optimal CBM development.

Alberta has a lot to gain from the ongoing research and development generated over the course of the growth of the U.S. CBM industry. Given their sudden growth pattern, there was little time to reflect on the need for, nor benefit of, baseline studies and other aspects of research and development. Gradually, as experience was gained from CBM production and often due to the need for resolve of specific areas of conflict, extensive and cooperative research and development has and continues to be conducted on issues related to the coals, the coal seams, the reservoirs, the sweet spots, drilling and completion technologies, and environmental aspects (water, air, noise, wildlife), to name just a few.

Finally, a number of other non-technical issues were raised during the U.S. discussions that need to be taken into account:

Safety

The need for blowout prevention equipment is at various stages of understanding and utilization across the basins. For instance, when speaking to operators in the San Juan, they stressed that expectations and regulations requiring BOPs should not be relaxed or any different than for conventional drilling. In the Powder River where drilling has largely been in the shallower horizons (200-900 feet) using truck mounted rigs, diverters have been required, but not BOPs. The requirement for BOPs was proposed by the Wyoming Oil & Gas Conservation Commission in 2000, after three incidents of uncontrolled flow occurred, but was opposed by industry for the following reasons:

- it represented an additional expense for what is usually a low pressure operation;
- the availability of BOPs that would actually be small enough to fit under the floor of a truck mounted drilling rig is limited and the cost considered excessive; and finally,
- to build a ramp and platform which would be required to accommodate a BOP (aside from the additional capital costs) would also result in additional surface disturbance.

The Wyoming Oil and Gas Conservation Commission (WOGCC) compromised by requiring that surface casing be set in all wells at which time the diverters would be installed on the well. The current thinking is that as CBM development progresses westward, with the combination of the more rugged terrain, deeper wells and higher pressures, the issue of BOP requirements may need to be revisited.[47]

Environmental

There are currently two field tests being conducted in the San Juan Basin utilizing enhanced CBM (ECBM) recovery technologies aimed at accelerating the rate of CBM production and proving up significantly greater levels of recoverable reserves. These ECBM technologies promote desorption of the sorbed phase gas through the injection of nitrogen or carbon dioxide into the coal bed reservoirs and have the potential to generate up to a six-fold increase in gas production rates and as much as a two-fold increase in recoverable gas reserves. The same coal bed reservoirs that are the source rock for CBM also have considerable potential for the sequestration of carbon dioxide and thus represent a significant opportunity to play a major role in reducing greenhouse gas emissions. Coal has an inherent capacity to act as a repository for CO_2 and such capacity varies inversely to coal rank. Amoco Production Company is currently involved in a full-scale nitrogen injection project in the Fruitland Formation and the results to date have been a three-fold increase in CBM production rates. Burlington Resources have been operating a 750 mcf/day/well CO_2 injection pilot project, also in the Fruitland Formation, with some enhancement observed. Of note, no CO_2 breakthrough has been observed at the production wells.[48] As the recoverable reserves in a basin become depleted under primary production technologies, the interest in enhanced technologies will continue to grow.

The occurrence of coal bed fires has been noted in various CBM basins such as on the Southern Ute Indian Tribe lands in the San Juan Basin. It has not been clearly identified; however, as to the role that CBM production has contributed to these situations. There is some evidence to suggest that the dewatering phase of the production process may be linked to a 'resurgence' in coal fires.

Noise pollution (from compressors, increased traffic, etc.) is an issue, particularly as CBM development advances and comes into contact with rural communities and landowners. Continuous monitoring and appropriate regulations are required.

Non-technical Mitigation Strategies

In summary, consistent with what the Alberta industry stakeholders identified through the Alberta Energy CBM Workshop, the U.S. experience concurs with the importance of multi-stakeholder task groups in order to enhance coordination, communication, and cooperation regarding all aspects of CBM development. This can and has been supplemented through the organization of public trade fairs. Also, strongly underlined

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[47] Discussions with Don Likwartz, Oil & Gas Supervisor, State of Wyoming, Oil & Gas Conservation Commission and Lynn Rust, Geologist/Minerals Analyst, Bureau of Land Management, Wyoming State Office.

[48] MGV Energy Inc. and gticanada, *Overview of Coalbed Methane*, 2000, p. 3-15.

were the importance of baseline studies and other aspects of research and development, which enhance the understanding of how to optimally develop a sustainable CBM industry.

Economic Issues and Mitigation Strategies

The economics behind the development of the CBM industry in the U.S. are dominated by the introduction of the Section 29 Tax Credit…even though today the emerging basin developments are doing so without the implications of this policy. Every stakeholder met with, producer, regulator and landowner alike, agreed that it was the single most important factor in kick-starting the U.S. CBM industry as we know it today. Each pointed out the significant economic benefits that have accrued as a result of this credit. While there were some suggestions as to how Section 29 could be enhanced (such as encouraging drilling at a more even pace as opposed to a 'last minute rush to meet the deadline', and a method of attributing a portion of the benefits of the credit toward mitigating some of the resulting infrastructure and environmental impacts), no person suggested it should not have been implemented. Of note, earlier this year Senate Bill S.596 was introduced which, if passed, would effectively extend the benefits of Section 29. As part of the '*Energy Security and Tax Incentive Policy Act* of 2001', Section 45K specifically would provide for a tax credit of $1.21/mcf for the capture of coal mine methane for use as a fuel source.

The economics behind CBM development varies greatly across the U.S. CBM basins. For the most part this is due to the fact that 'no two basins are the same'. As has been discussed throughout this section, each area has its own set of technical characteristics that drive the specific economics. Therefore, when reflecting on mitigation strategies that might be considered for Alberta, it is evident that any solution must be a 'made in Alberta' solution.

Further U.S. Lessons

An effective land use plan is essential for a sustainable CBM industry. It must be recognized up front that along with the many positives associated with a new energy industry comes the need for more permits, more qualified people both on the administrative and operations side, more wells, more roads, and very importantly the demand for more power. Since CBM is produced from low-pressure reservoirs (perhaps 30 pounds per square inch (psi)) and must be compressed significantly (1000 - 1200 psi) to be transported to market, the industry requires increasing levels of electricity. In addition to the power associated with compressors, the need for submersible pumps to displace potentially large volumes of water also adds to the industry's power requirements. Some U.S. CBM producers are turning to supplemental power sources (small diesel generators) to meet their ongoing needs. This, in turn, has created other concerns including higher operating costs and environmental issues such as increased air and noise pollution. In Alberta, where the producers of electricity have at times this past year struggled to meet growing domestic demand while recognizing the growing value in the export market, the issue of adequate power supplies must be taken into account at the outset of a developing CBM industry.

V. ESTABLISHING AN ECONOMIC FRAMEWORK FOR SUSTAINABLE DEVELOPMENT

Increasing demand for natural gas, encouraging price forecasts, and excess export pipeline capacity are all positive factors influencing the growing interest in CBM development in Alberta. This section will provide an economic framework for sustainable development of CBM to serve as both a template against which future 'real data' can be compared and a mechanism for evaluating the impact of potential mitigation strategies.

There is no known commercial production of CBM in Canada so the economic analogies and financial statistics presented herein have been provided from producers and, for the most part, is drawn from their historical experience in the U.S. and other CBM producing countries. CBM exploration is at the pioneer stage in Alberta. The provincial coal basins are essentially unproven from a CBM perspective, making exploration very risky, as there are no established trends to rely on. Determining permeability has been described as difficult and frustrating and may require large numbers of wells to be drilled before reservoir characteristics are fully understood.

In examining the potential for CBM development for Alberta, companies will be confronted with a number of additional technical and economic constraints.

- Large contiguous land positions are required to capture sufficient potential reserves in CBM project areas to ensure economic viability.
- Volumetric determinations of gas-in-place and the potential for recovery require gas content and desorption data from cores under laboratory conditions.
- Drilling and completion costs can range significantly, depending on such things as the type and depth of coal, permeability, number of zones perforated, and type of technology used. Costs tend to increase where the coals are deep and of low permeability.
- Many CBM wells produce low volumes of gas and potentially high volumes of water, particularly during the depressurizing/dewatering phase. The delayed CBM production negatively impacts economic cash flow projections.
- Multi-well pilot programs are needed to determine the producibility of a play. This is a critical assessment phase for any project as reserve size and deliverability need to be determined prior to construction of associated distribution systems.
- CBM wells are characterized by relatively low producing pressures and large diameter gathering lines may need to be constructed along with significant compression facilities to move the gas into existing pipelines.
- As with any P&NG project, environmental impact studies, permit delays, pipeline constraints, etc., can also impact the economics of CBM development.
- CBM projects will need to compete for funding (corporately and in the marketplace) against other energy opportunities such as frontier and unconventional gas projects, thus timing is noted to be of the essence.

The development of a database of typical financial variables is substantially compromised by the above noted technical and economic constraints. Table 5 represents the geological characteristics of the Plains (Shallow Basin), Central (Deep Basin), and Foothills coal areas of Alberta, the areas around which this economic framework is based.

Table 5
Geological Characteristics of Alberta CBM Basins

Characteristic	Shallow Basin	Deep Basin	Foothills & Mountains
Coal Thickness	5-15 m	2-11 m	2-15 m
Depth	300-900 m	900-3000 m	200-1600 m
Ash Content	15-20 per cent	5-15 per cent	5-25 per cent
Coal Rank	Sub-bituminous C	High volatile A bituminous	High volatile A to semi-anthracite
Gas Content	2-4 cc/g	8-15 cc/g	8-20 cc/g
Permeability	1-10 md	<0.1-2 md	<0.1-5 md
Water Flow	Topography driven	Erosional rebound	Topography driven
Water Salinity	Fresh	Saline to brine	Fresh
Infrastructure	Good	Good	Poor

Source: Alberta Geological Survey; Geological Survey of Canada[49]

To begin with, natural gas prices are one of the most important factors driving the current interest in CBM and as indicated in Figure 14, prices over the past 18 months have been strong. The Gilbert Laustsen Jung price forecast (Figure 15), which suggests continued favorable prices, was used to run the economic base case scenarios included in this section. Table 6 includes the range of costs gathered from producers throughout the survey process and the actual ('proposed') numbers used to run the various scenarios. In all cases, the costs used fall within the ranges provided from the survey results. However, as shown, some of the costs used reflect the high end of the survey range (i.e., permitting and site preparation), whereas, others used were from the lower end (i.e., water disposal costs). The final determination of which costs to run in the analysis was made with support from an economic Sub-Committee. (Note: Land costs are not included as they were considered a competitive factor, nevertheless, it should be recognized that because of the need for a 'large contiguous land tract', relative to conventional drilling, land costs represent a significant financial risk at the exploratory stage.)

The economic scenarios are based on a one-township project with 144 wells drilled on 160-acre spacings. A five-spot pilot test, which had a 25 per cent success rate, is

[49] Stefan Bachu*, Alberta Geological Survey; F. Michael Dawson, Geological Survey of Canada; Richard J.H. Richardson, Alberta Geological Survey; "Regional-Scale Characterization of Coal-Bed Methane Reservoirs in the Alberta Basin in Comparison with Other Rocky Mountain Basins."

assumed to have triggered development and the remaining 139 wells drilled were considered to be 100 per cent successful. Of note, the projected construction 's' curve included drilling 11 wells in year one, 40 in year two, 60 in year three, and 33 in year four. The analysis covers a 20-year period, however, natural gas production continues to flow and generate cash flow beyond this time frame.

Figure 14

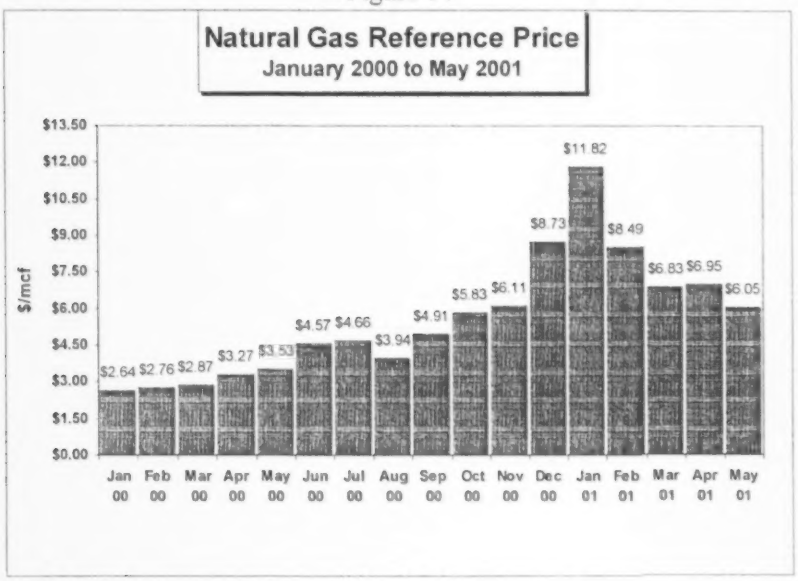


Figure 15

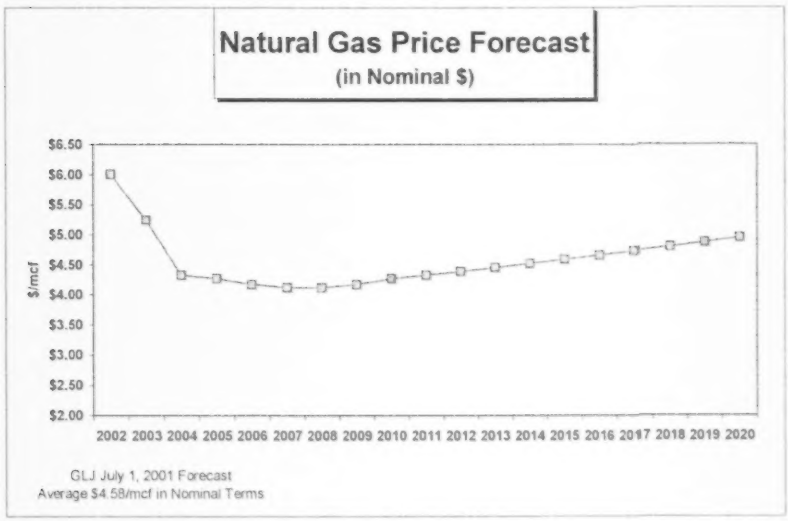


Table 6. Coalbed Methane Economics - Proposed Costs ($000)

Economics are based on 144 wells, 5 test wells with a 25 per cent success ratio, the remaining 139 wells are 100 per cent successful.

Investment Costs ($000)

	Foothills		Central		Plains	
	Proposed ($)	*Survey ($)*	*Proposed ($)*	*Survey ($)*	*Proposed ($)*	*Survey ($)*
Lease Acquisition		10 - 50		5 - 50		5 - 50
Permitting and Site Preparation	100	30 - 100	50	35 - 50	50	35 - 50

Capital Costs ($000)

	Foothills		Central		Plains	
	Proposed ($)	*Survey ($)*	*Proposed ($)*	*Survey ($)*	*Proposed ($)*	*Survey ($)*
Drill	338	200 - 700	231	200	201	150
Complete		80 - 150		100		50
Stimulate	100	80 - 100	100	80 - 120	100	50 - 120
Tie-in	70	70	70	70	70	70
Collection/ Compression/ Processing	200	100 - 250	200	80 - 500	100	50 - 225
Water Disposal	125	125	110	110	100	100
Dry Hole Costs (average for project)	* 12.2		9.2		8.3	

Operating Costs

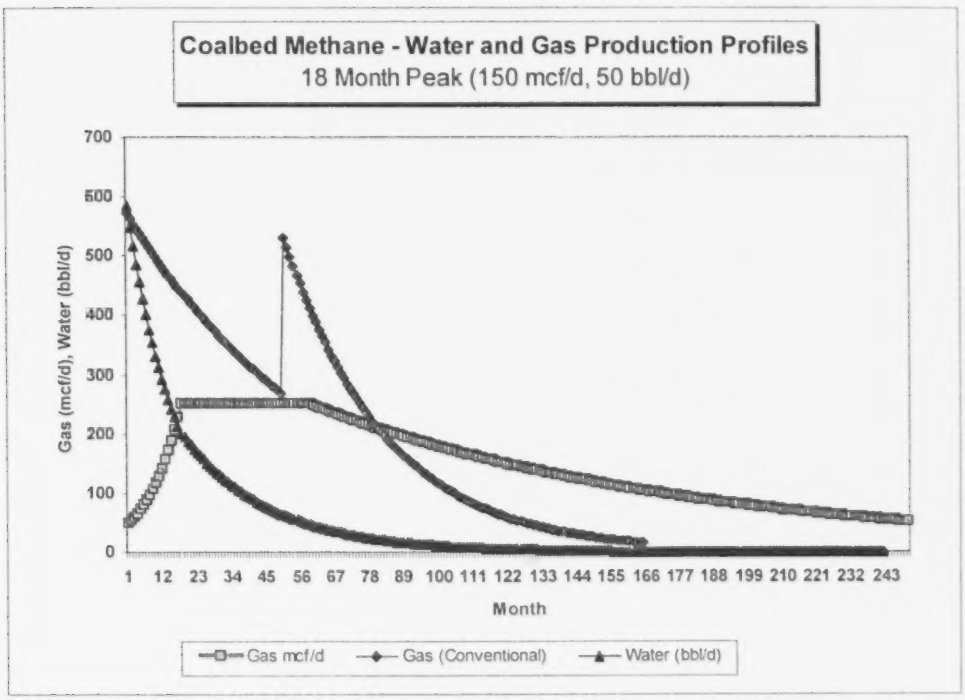
	Foothills		Central		Plains	
	Proposed ($)	*Survey ($)*	*Proposed ($)*	*Survey ($)*	*Proposed ($)*	*Survey ($)*
Gas Processing ($/mcf)	0.4	0.35 - 0.45	0.35	0.30 - 0.40	0.35	0.35 - 0.40
Water Disposal ($/bbl)	0.25	1.00	0.25	0.25 - 1.00	0.25	0.10 - 0.30
Overhead ($/month)	2000	1300 - 2100	1500	1250 - 2600	800	800 - 1500

Note: * $\frac{(338 + 100) / .25}{144} = 12.2$

The production profiles indicated in Figure 16, compare production from a typical conventional natural gas well under the new royalty regime with what producers thought they might expect from a CBM well[50] (in the Plains or Central regions) where gas production peaks after eighteen months and averages 150 mcf/d. In this Base Case, water production averages 50 bbl/d with recoverable reserves from each well being approximately 1.1 bcf. Note that the production profiles could be significantly different (see Figure 17), with natural gas production peaking much further out and not displaying any leveling of production. The production profile assumed for these cases implies that when developing a CBM project, producers will drill wells and build facilities to support sustainable production levels, rather than overbuilding to meet the peak level. Two additional implications to acknowledge are:

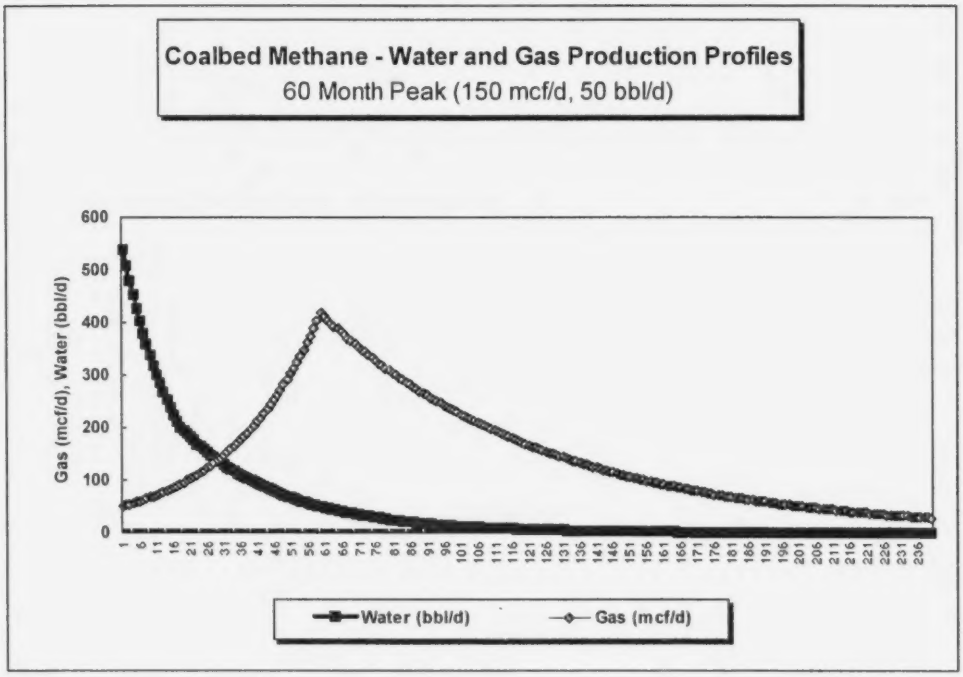
(i) the front-end depressurizing or dewatering phase associated with a CBM well increases the front-end risk and extends the payout period; and,
(ii) due to the inherent dewatering normally required, CBM wells cannot be shut-in and restarted without recognizing that during the shut-in phase the coal aquifer will be recharged, necessitating the need to begin the dewatering phase all over again.

Figure 16



[50] The fiscal and economic attributes of the CBM industry reflect conventional CBM development and exploitation technologies.

Figure 17



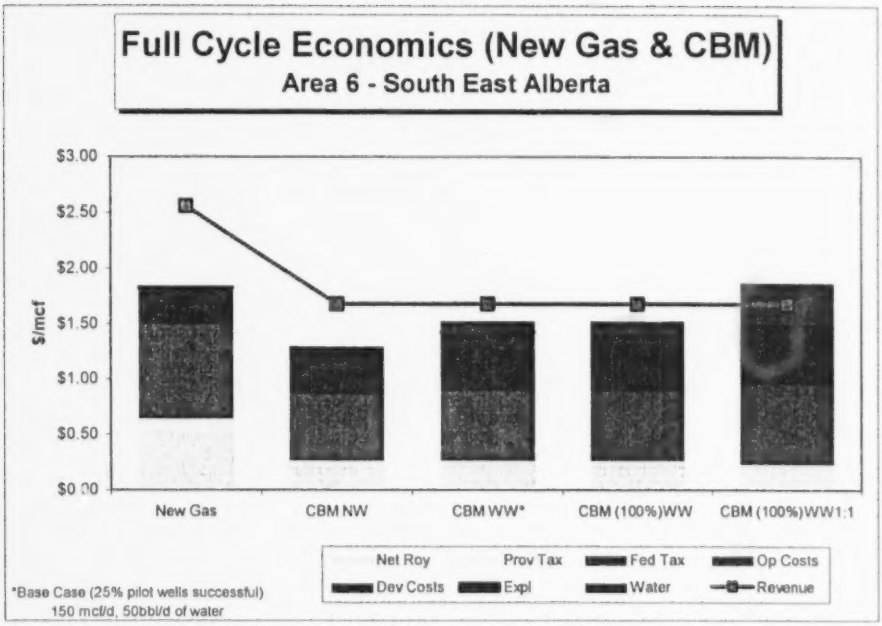
The next four graphs (Figures 18 - 21) are the results from the analysis performed for the Plains region (Area 6[51] - South East Alberta). Figure 18 compares the net present value (NPV) of the revenue in $/mcf for a typical conventional new gas project (Bar 1) in this region with the following:

- Bar 2: CBM with no associated water (NW);
- Bar 3: Base Case, CBM with water (WW) (150 mcf/d of gas and 50 bbl/d of water; pilot wells assumed 25 per cent successful with dry hole costs shared across the remainder of the wells in the project);
- Bar 4: Same as Bar 3 only the pilot was assumed to be 100 per cent successful; and,
- Bar 5: Same as Bar 4 with water production levels averaging 150 bbl/d (1:1).

(Note, in Figures 18-24, the gap between the discounted NPV of the revenues (the revenue curve) and the discounted NPV of the supply costs (cost bars) represents the net present value of the profits/mcf; therefore, the larger the gap, the greater the incentive to undertake the project.)

[51] As designated by the Independent Petroleum Association of Canada (IPAC).

Figure 18



It should be noted that because this industry is in its infancy, the initial pilot projects could be expected to have much poorer success rates than indicated in the Base Case. On the other hand, as experience is gained, producers expect the success rates to be closer to 100 per cent. (In this regard, many survey participants compared CBM to the history of oil sands development where once the required production technologies were determined, exploration costs became negligible.)

Keeping in mind that the analysis herein is based upon data, none of which has been substantiated by commercial production in Alberta, the assumptions suggest that CBM economics are marginal. Discounted revenues to the producer are 80 per cent of those received under the conventional scenario, with development, operating and water disposal costs being critical economic factors. Total supply costs, on a discounted basis however, are very similar (98.8 per cent of conventional) because the incremental costs associated with the CBM case are spread out over a longer production cycle. Exploration costs on a project basis have little impact (as is further demonstrated by the 100 per cent successful scenario, Bar 4) but, relative to conventional gas, are significantly lower. Fiscal take generated under the CBM scenario is 40 per cent less than for the conventional case; federal taxes paid are 43 per cent less, provincial taxes 58 per cent less and royalties 33 per cent less. In total, provincial take is 63 per cent less under the CBM scenario. As would be expected, disposing of water on a one-to-one ratio with the gas produced does not bode well with the economics and as shown in Bar 5, would result in negative returns to the producer.

Sensitivities were run against the natural gas price forecast (Figure 19), water disposal costs (Figure 20), and capital costs (Figure 21). The overall impact of the sensitivities can be interpreted as follows.

- A drop in price of $0.50/mcf would result in a reduction in net present value (NPV) to the producer of $0.12/mcf.
- An increase of $0.50/bbl on water handling costs has a negative impact on NPV of $0.14/mcf.
- A 25 per cent decrease in capital costs increases returns by $0.10/mcf.

Based on these assumptions, this would suggest that a $0.50 decrease in water costs would have a more positive impact on the producer than a $0.50/mcf increase in price or a 25 per cent reduction in capital costs.

Overall, as CBM economics are indicated as being less attractive than for conventional gas, it can be expected that CBM will be more sensitive to price, water handling costs and capital, resulting in more extreme volatility. As well, the range of possible values used in the analysis for each variable must also be considered. For example, while prices have ranged significantly, water-handling costs can be controlled and are not likely to experience such wide fluctuations. Similarly, capital costs may have a larger impact depending on what values are used initially and the range of possible costs examined.

Figure 19

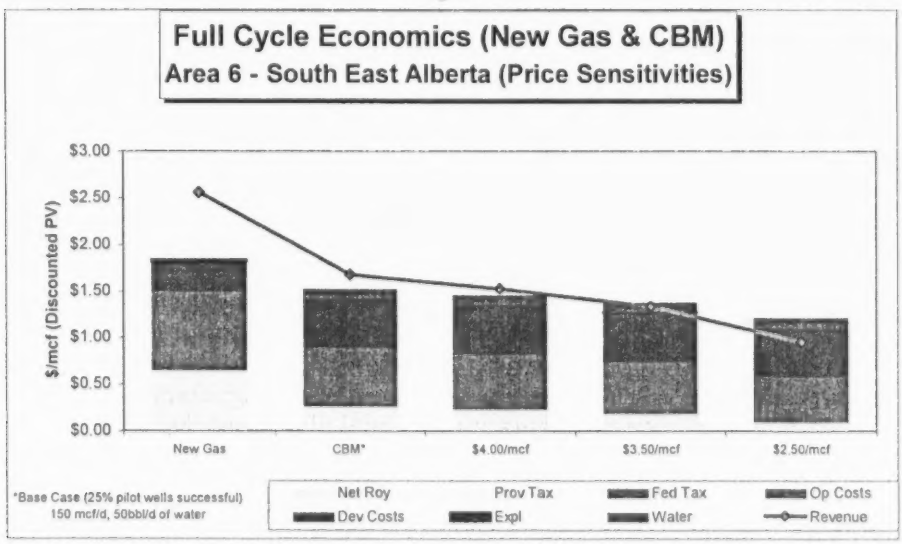


Figure 20

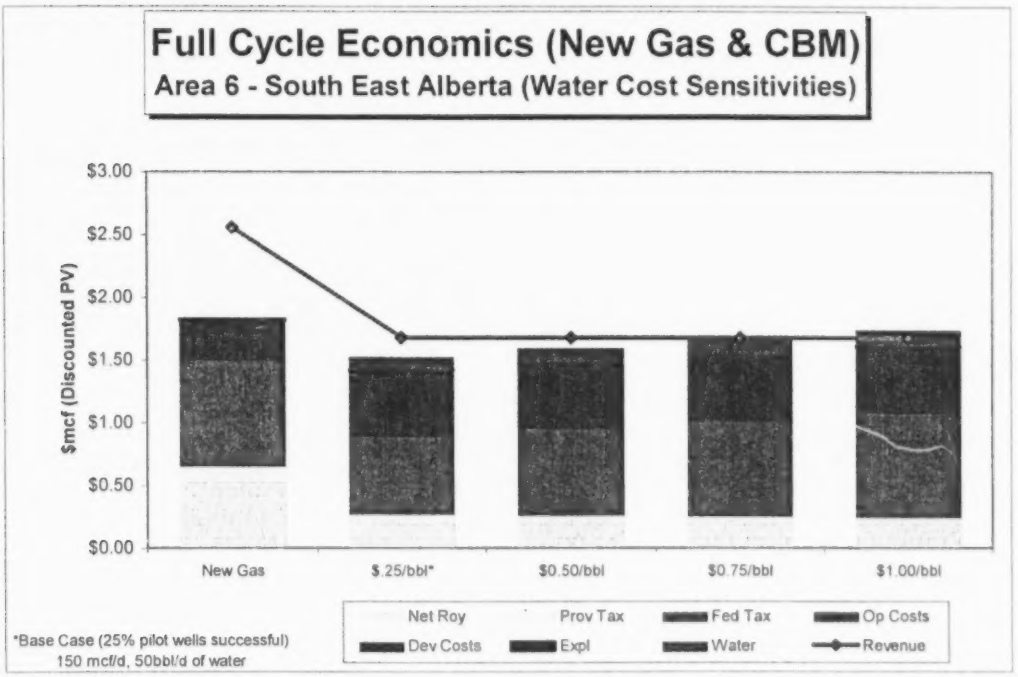
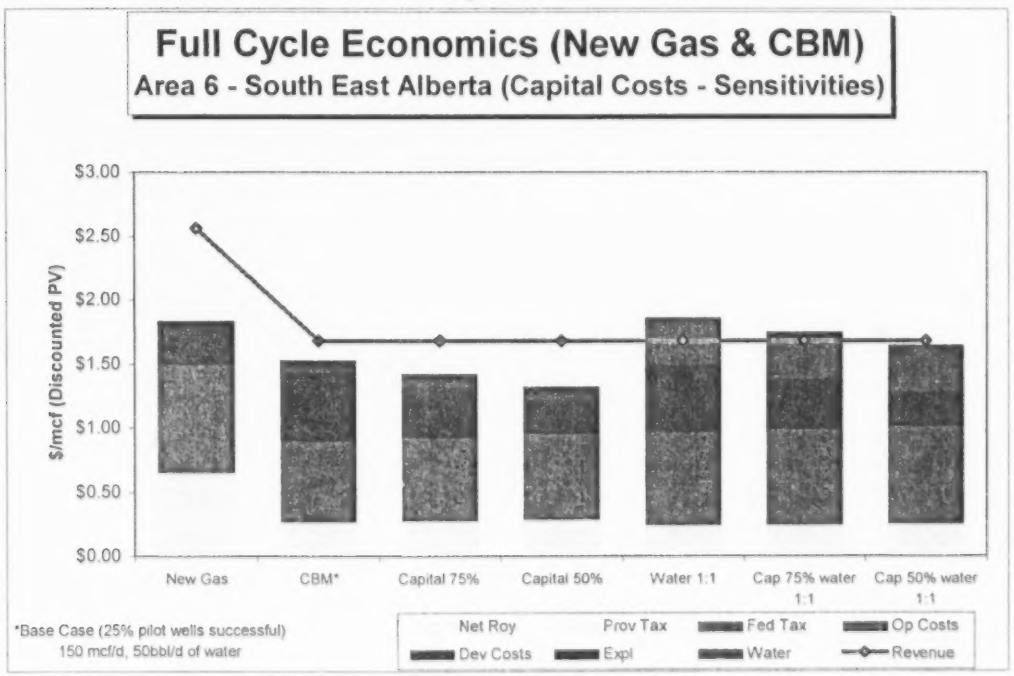


Figure 21



As would be expected if daily production rates were the same for all three regions analyzed, the Plains, Central and Foothills, the higher costs expected and assumed for the Central and Foothills projects would generate lower overall returns (see Figures 22 and 23). It should be noted that in the Foothills, however, there is an expectation of greater volumes of CBM, therefore, a 300 mcf/d case has been included (see Figure 24). Under this scenario, it appears that doubling the natural gas production in the Foothills offsets the incremental costs expected, with the returns to the producer being similar to the 150 mcf/d case for the Plains area.

Figure 22

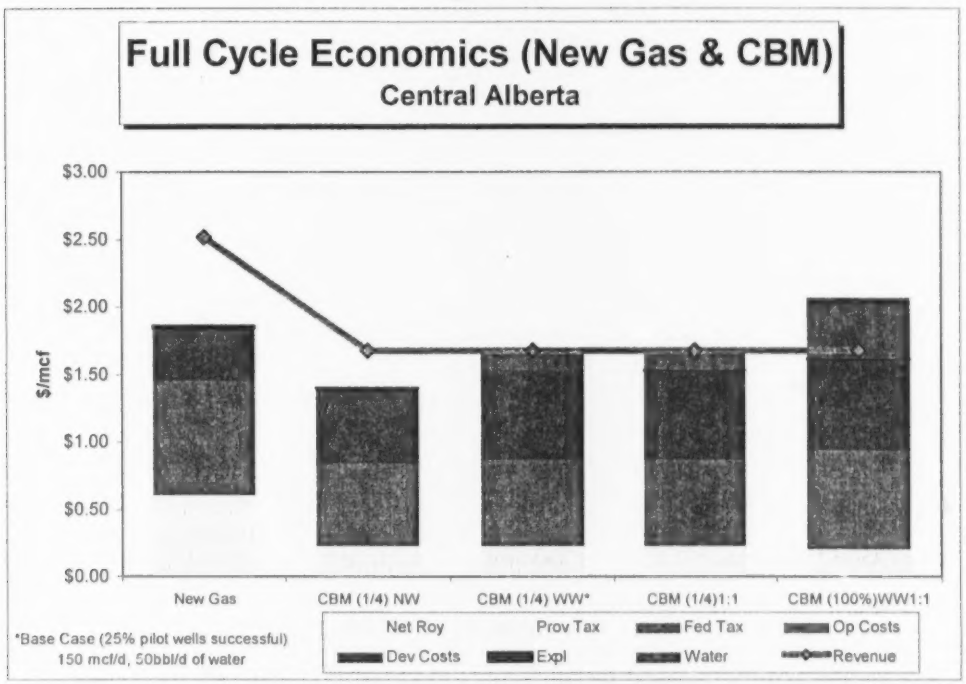


Figure 23

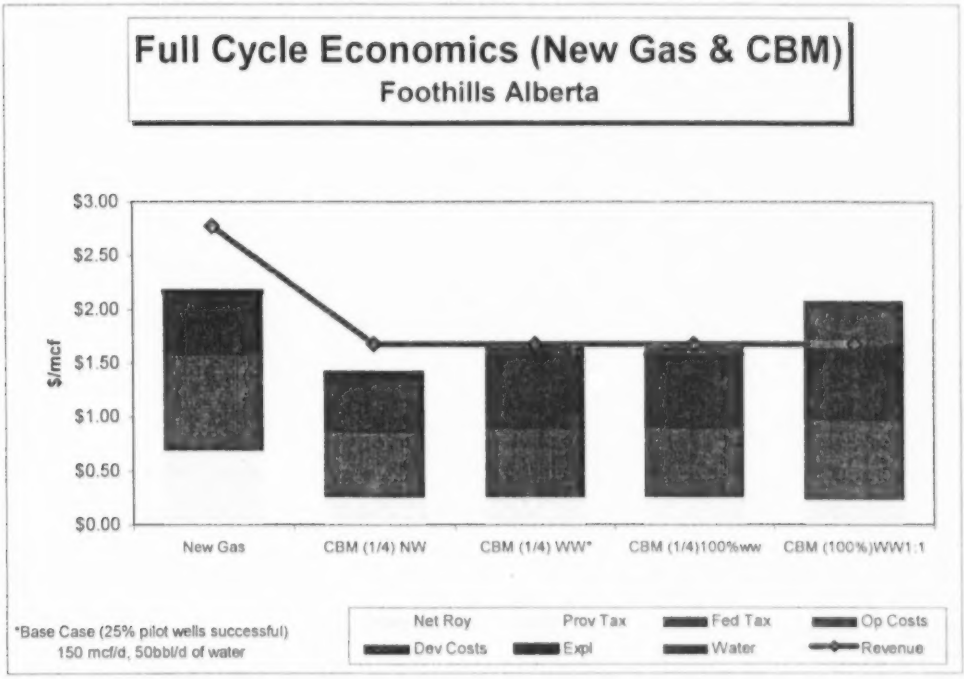
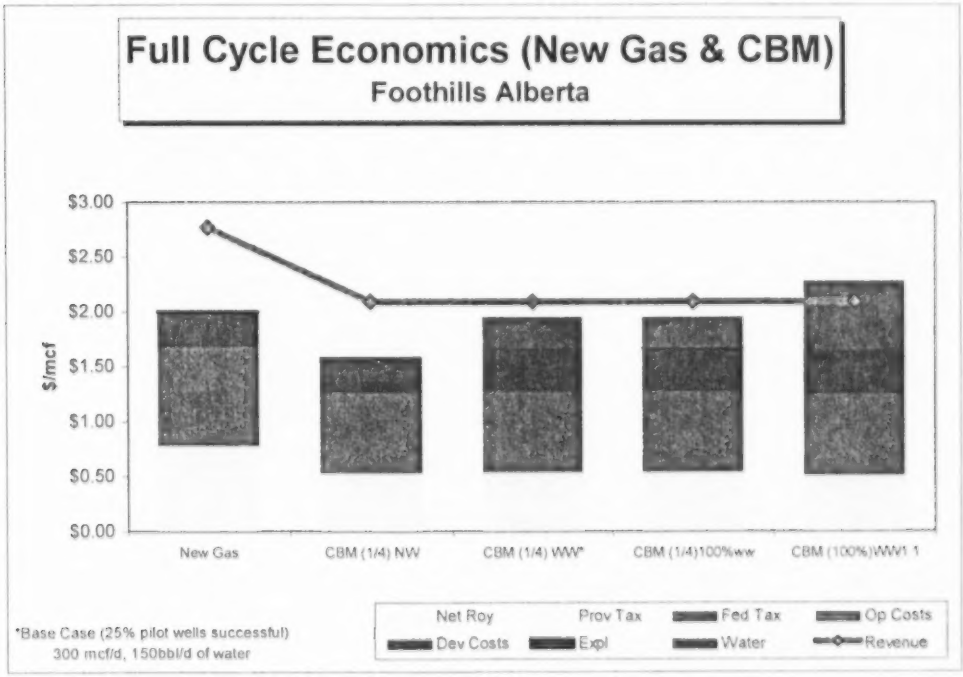


Figure 24



In consideration of the mitigation strategies previously identified, the analysis would suggest that there are a number of options, which the Alberta Government could consider in their CBM development strategy.

Given the proving up phase and the potential for a lengthy depressurizing/dewatering stage, an upfront credit would encourage drilling activity.

- Due to the economic impact of the large upfront capital requirements, some form of recognition may be appropriate for the incremental costs, which are unique to CBM.
- The impact of water handling costs is evident from the analysis; recognition of these costs, perhaps through the Gas Cost Allowance, would have a positive leveling effect on CBM versus conventional economics.
- Lower royalty rates and/or no royalties until payout were suggested as other mitigating options. The analysis suggests there is some room for this; however, CBM wells are expected to have low-productivity, which automatically qualifies them for lower royalty rates.

The modeling procedures used for this analysis were based upon sound economic principles. It must be reiterated, however, that the data used for the analysis is a collective interpretation of what the surveyed industry stakeholders might expect to apply to CBM projects in Alberta. The results are simply an economic framework against which companies can compare their own CBM project analysis and which governments can use to examine potential resource development strategies. The reader should focus, therefore, on the trends and realize that changes to any of the key variables will understandably affect the results.

VI. OBSERVATIONS AND CONCLUSIONS

This study has benefited from the diligent input of a significant number of CBM stakeholders. It has highlighted the fact that there is strong and growing interest in the potential to exploit the natural gas opportunities stored in Alberta's extensive coal beds. Some of the salient observations and lessons learned include the following:

- no two CBM basins are the same;
- having good baseline resource inventory data is critical;
- evolving management, drilling and completion techniques have and will continue to enhance the economic understanding; and,
- since there is no publicly recognized commercial production of CBM in Alberta, stakeholders have the opportunity to learn from the technical, economic and environmental strategies, which have been developed and tested in the U.S.

Taking into consideration the priority issues identified through the survey and consultative process of this study, along with the experiences shared by U.S. stakeholders, the following mitigation strategies suggested by industry may be applicable to CBM development in Alberta.

Potential Technical Mitigation Strategies

There is no substitution for drilling, continuous research and data analysis, and the public dissemination of this knowledge in order to resolve the technical barriers and identify the optimal completion and production technologies (balanced with the appropriate consideration for confidentiality).

'CBM wells' must be classified as such and the associated information requirements should include gas contents of the coals, achievable production rates, and the composition of the gas.

Potential Land Access and Tenure Strategies

The challenge of assembling large contiguous tracts of land (needed to achieve sufficient scale to be economically attractive and provide expansion opportunities throughout the various stages of development) has largely been sorted out in the U.S. through the marketplace. In Alberta, this could require a series of interim steps and longer-term solutions. Short-term resolutions could include development of clear definitions for test wells and experimental schemes, flexibility around Section 17 of the *Petroleum and Natural Gas Tenure Regulation*, and a review of the rules as they apply to continuation.

Well spacing requirements will need to be reviewed and revised as the current stipulation of 'one well per section' is insufficient for the degree of communication necessary between well bores to optimally depressurize and stimulate CBM production.

Further review is required of the benefits and implications of unitization.

Potential Water Disposal and Diversion Mitigation Strategies

Current regulations governing the disposal and/or diversion of water in Alberta pose significant obstacles and potentially are CBM 'project breakers'. Inherent to CBM production is the need to dewater the coal seams. As noted by the participants in the CBM Workshop, this suggests that policy changes are required to allow for the dewatering of non-saline aquifers as well as consideration of surface discharge.

Baseline studies on a project basis will assist in developing the appropriate water handling options.

Potential Non-technical Mitigation Strategies

Consistent with what the Alberta stakeholders identified through the CBM workshop, U.S. experience concurs with the importance of multi-stakeholder task groups in order to enhance coordination, communication and cooperation regarding all aspects of CBM development.

Ongoing research and development of non-site-specific issues is essential.

Potential Economic Mitigation Strategies

The major economic hurdles associated with the development of a CBM industry in Alberta relate to expectations of low productivity, significant upfront costs and long payout periods. Stakeholders suggested the need for a fiscal and economic framework, which recognizes the specific incremental operating and capital costs associated with CBM production.

A fair and reasonable incentive should be considered which would encourage the industry to drill, for a time period sufficient to gain the necessary technical understanding of the potential for producing CBM in Alberta.

The outlook for the development of a sustainable CBM industry in Alberta is positive. The province has vast resources of coal, estimates of significant CBM recoverable reserves, a highly skilled workforce that is widely recognized for their expertise and adaptability, an extensive and efficient natural gas distribution system, a growing demand for natural gas resources, expectations for reasonable natural gas prices, and incremental export pipeline capacity. It is important, therefore, to take time to acknowledge the hurdles and design the appropriate regulatory and economic strategies.

Industry has suggested there is need to:

- determine a fair and reasonable manner to encourage drilling;
- establish a CBM Advisory Group to examine emerging regulatory/policy requirements;
- encourage baseline analysis, (e.g., methane gas seepage and basin-wide/watershed studies) and continuous research and development of the coals, the coal reservoirs, the sweet spots, drilling and completion technologies and environmental aspects (water, air, noise, wildlife), etc.

- develop the economic framework for ongoing production forecasting as data becomes available;
- examine the impact of CBM development on power requirements and related infrastructure needs;
- continue the examination of enhanced CBM production implications;
- examine administrative manpower requirements; and finally,
- encourage the public consultation process through such initiatives as workshops, road/trade shows, a CBM website, and development of a 'made in Alberta' CBM pamphlet

The next steps toward development of a sustainable CBM industry will be critical.

APPENDICES

I. Alberta Energy and Utilities Board Informational Letter 91-11 and Related Regulations Pertinent to Coalbed Methane

II. United States Section 29 Tax Credit

III. Stages of Coalbed Methane Production

IV. Powder River Basin, United States Geological Survey

BIBLIOGRAPHY

APPENDIX I

EUB Alberta Energy and Utilities Board

Informational Letter IL 91-11

To: All Oil and Gas Operators and Coal Operators 26 August 1991

COALBED METHANE REGULATION

SUMMARY

There is currently considerable interest in the evaluation of coalbed methane in Alberta. The Energy Resources Conservation Board (ERCB) and the Alberta Department of Energy (Energy) believe that some tests of Alberta coalbed methane production are necessary as a basis for long term regulatory policies. Furthermore, the ERCB and Energy propose that a task group be established to monitor coalbed methane development and recommend appropriate regulatory policies based on Alberta information. In the interim, the preliminary regulatory provisions outlined in the following will be applied, subject to revision when and as needed.

ALBERTA DATABASE

Little evaluation of Alberta coalbed methane has occurred to date. The ERCB and Energy believe that Alberta specific data is necessary as a basis to develop appropriate long term regulatory policies. It would therefore be helpful for a number of small scale production tests to proceed at this time.

FORMATION OF COALBED METHANE TASK GROUP

The ERCB and Energy will seek to establish a task group comprised of industry, government, and public representatives to monitor coalbed methane evaluation and development. The group would develop and recommend appropriate regulatory policies and practices to be applied in the future.

PRELIMINARY REGULATORY PROVISIONS

The ERCB and Energy consider coalbed methane to be a form of natural gas. As a result, all acts and regulations administered by the ERCB and Energy that pertain to natural gas also pertain to coalbed methane. Applicable legislation under the jurisdiction of the ERCB and Energy includes the Energy Resources Conservation Act, the Gas Resources Preservation Act, the Oil and Gas Conservation Act, the Mines and Minerals Act, and regulations related to these acts.

It appears that most ERCB and Energy practices and policies relating to the drilling and production of conventional gas reservoirs can be applied directly to coalbed methane. Some

specific aspects of mineral leasing, drilling, completion and production of wells, data requirements, and experimental schemes are discussed in more detail in the following.

1 Crown Mineral Leases

The right to Crown natural gas is governed by the Mines and Minerals Act (Act). In the Act, natural gas and coal are treated as distinct substances and are leased separately. This principle recognizes that natural gas may exist in a variety of reservoir rocks, including coal seams. Energy does not consider a coal lessee as having any right to natural gas except in those cases where sections 65(2) and 92(5) of the Act have been invoked.

In Part 2 of the Act, which pertains to coal, section 65(2) states:

"The Minister, on the recommendation of the Energy Resources Conservation Board that it is necessary to do so for safety or conservation reasons, may authorize the lessee of a coal lease to recover natural gas contained in a coal seam in the location of the coal lease."

In Part 5 of the Act, which pertains to Petroleum and natural gas, section 92(5) states:

"An agreement granting rights to which this part applies does not grant the right to natural gas in a coal seam that the Minister has authorized the lessee of a coal lease to recover under section 65(2). "

When these two sections of the Act are invoked, section 65(2) would convey the natural gas rights within the coal seam to the coal lessee and section 92(5) would remove the natural gas rights within the coal seam from the natural gas rights lessee. Both sections of the Act would be administered in tandem and only in those instances where a coal mine operator had applied to the ERCB for the safety reasons specified, or the ERCB was of the opinion it was necessary for conservation reasons, and the ERCB recommended to the Minister that the legislation be applied.

Petroleum and natural gas agreements are continued pursuant to Part 5 of the Mines and Minerals Act. In order for an agreement to be continued, a lessee must demonstrate that the agreement is capable of producing petroleum or natural gas in paying quantity from a zone in the location of the agreement in which rights to that petroleum or natural gas are granted. Petroleum and natural gas agreements will not be continued based solely on the presence of coal.

2 Well Licensing

Applications for well licences must be in accordance with the requirements of ERCB Guide G-33, and state that the purpose of the well is to obtain coalbed methane production from one or more specified geological formations, as listed in the ERCB Table of Formations, Alberta. ERCB Informational Letter IL 82-1 sets out additional well licence application requirements in coal field areas. If desired, the ERCB could maintain and make available a list of wells targeting coalbed methane.

3 Surface Leases

Surface access and surface leases must be acquired from the Crown or private owners in the normal manner. Surface disturbance must be minimized in development and use of the lease. Issues of environmental and social impacts must be addressed and the concerns and objections of directly and adversely affected persons must be addressed as for any other gas well.

4 Well Spacing

Normal gas well spacing of one well per section applies, unless a change is approved under the Oil and Gas Conservation Regulations, section 4.030. The effects on gas recovery, equity, and surface impacts will be considered in any change.

5 Drilling and Completion

Use of standard drilling and servicing rigs, blowout prevention equipment, casing design, and cementing practices will be expected unless application for variance is approved. Such applications must be submitted prior to the filing of well licence applications for drilling, and prior to initial completion for servicing.

6 Production

Production facilities require ERCB approval in accordance with section 7.001 of the Oil and Gas Conservation Regulations. As with drilling, operators will be required to address all environmental and social impacts, and to address objections of directly and adversely affected persons. In particular, handling and disposal of the expected water production and possibly coal-fines need to be carefully planned, and appropriate approvals for disposal schemes obtained. Options for water disposal include treatment and release to the watershed, or subsurface disposal to a compatible formation.

The impact that coal seam dewatering may have on area ground water aquifers must be addressed before large scale water withdrawals commence from any coal seam. If the produced water is potable, there is a possibility that Ground Water Removal permits may be required by the Department of Environment under the Ground Water Development Act and the Water Resources Act.

7 Data Reporting Requirements and Confidentiality

All basic well data including drilling, completion, and production data must be submitted as for conventional oil and gas wells, and will be released as provided for in the applicable existing regulations. For wells classed as confidential under the Oil and Gas Conservation Regulations, section 12.150(l), basic data including logs, cores, samples, routine core analyses, pressure measurements, and flow tests are held confidential for l year from the finished drilling date of the well. Wells which are placed on production or designated as a part of a non-confidential pool may be released earlier.

For an interim period, the ERCB is prepared to classify all analyses of core and drill cuttings from wells drilled to evaluate coalbed methane potential as "non-routine" under the OH and

Gas Conservation Regulations section 11.040(2). All reports or measurements obtained from these core analyses and samples, must be submitted to the ERCB within 6 months of the date of the analyses. These data will be held confidential for 1 year from the date of the analyses in accordance with section 12.150(5)(a) of the Oil and Gas Conservation Regulations.

To provide a basis for decisions regarding the handling and disposal of produced fluids, gas and water sample analyses must be submitted in accordance with the Oil and Gas Conservation Regulations, section 11.070.

For confidentiality beyond the limits described above, experimental schemes can be applied for as discussed in the following.

8 Experimental Schemes

It is expected that extended testing of initial evaluation wells may be required, and it may be appropriate for certain test data to be held confidential for a period of time. To provide for this, application may be made for experimental schemes, under which the results from flow tests during drilling and extended production tests after completion could be held confidential for a period of time. Certain additional information could also be considered for extended terms of confidentiality.

The ERCB believes that the confidentiality period should be limited to 2 to 3 years from the commencement date of an experimental scheme. This is based on a scenario in which drilling of a well and construction of test production facilities using conventional methods may require in the order of 6 months. Flow testing may require a few months to possibly a year. This would then allow a further 1 to 2-year confidentiality period to protect the investment involved in the pilot project.

Applications for experimental schemes must address the criteria set out in IL-OG 78-12 and must include at least the following information:

- purpose of the Project
- requested term Of approval
- information and data requested to be held confidential
- description of potential environmental impacts

Gas rates during the initial stages of production may be very low and gathering of the gas may not be justified. The ERCB would thus be prepared to consider allowing extended flaring of gas production, provided that no significant environmental damage occurs.

Coalbed methane experimental schemes will be listed in the ERCB's regular monthly listing of experimental schemes (Alberta Approved Projects, Monthly Supplement, ST "Year"-44) available to the public.

The ERCB and Energy believe that a number of evaluation projects will be undertaken in various parts of Alberta in the near future. These are expected to involve only a few wells and hence would likely have minimal environmental and social impacts.

9 Commercial Development

If a project extends to intensive exploration or commercial development and is an area with potentially conflicting land use, then the filing of an overall development plan may be required, particularly if reduced spacing is being contemplated and/or environmental and social impacts are likely to be significant. This issue will be further addressed by the proposed Task Group.

Additionally, although minimized surface disturbance and proper reclamation are expected in any scale of development, these matters will be of particular interest at the commercial development stage.

10 Crown Royalties

The approval of an experimental scheme by the ERCB does not in any way obligate Energy to grant any special royalty consideration.

Questions regarding this informational letter should be directed to Mr. Harold Keushnig of the ERCB's Gas Department at 297-8511 or to Mr. David Luff of the Department of Energy at 427-7749.

<signed by>

F. J. Mink
Vice Chairman
Energy Resources Conservation Board

and

M. F. Kanik
Deputy Minister
Department of Energy

OIL AND GAS CONSERVATION REGULATIONS

Part 1	Interpretations
Part 2	**Licensing of Wells**
Part 3	**Approval of Drilling and Completion Operations**
Part 4	**Drilling Spacing Units and Target Areas**
Part 5	**Blocks, Projects and Holdings**
Part 6	**Drilling, Completing and Servicing**
Part 7	**Production Operations**
Part 8	**Prevention of Losses, Injuries, Damages and Fires**
Part 9	Ethane Supply for Straddle Plants
Part 10	**Production Rates and Accounting**
Part 11	**Well Data**
Part 12	**Records and Reports**
Part 13	**Well and Battery Names**
Part 14	**Measurement**
Part 15	**Certain Applications**
Part 16	Levies on Wells and Oil Sands Projects
Part 17	Schedule of Fees
Part 18	Coming Into Force

Schedule 5	Tabulation of Basic Well Rates
Schedule 6	Gas-Oil Ratio (GOR) Penalty Factor Formula
Schedule 8	**Blowout Prevention Systems**
Schedule 9	**Standards of Accuracy for Oil, Gas and Water Production**
Schedule 10	**Servicing Blowout Prevention Systems**
Schedule 11	**Equipment Spacing for Well Servicing**
Schedule 12	Signage
Schedule 13	Target areas as per Section 4.030
Schedule 14	Off-target Penalty Factors

Bolded items most directly relevant to CBM development

EUB GUIDE Reference for CBM

Guide 40	Pressure and Deliverability Testing Oil and Gas Wells, Minimum Requirements and Recommended Practices
Guide 51	Injection and Disposal Wells, Well Classifications, Completions, Logging, and Testing Requirements
Guide 56	Energy Development Application Guide and Schedules
Guide 60	Upstream Petroleum Industry Flaring Guide
Guide 65	Resources Applications For Conventional Oil and Gas Reservoirs

POLICY DOCUMENT References for CBM
Informational Letters (IL)

IL-OG 78-12	Policy on Experimental Schemes – Conventional Oil Pools or Oil Sands
IL 80-23	Experimental Schemes – Release of Applications and Basic Well and Geological Records; Confidentiality Provisions For Unique Design Data and Progress Reports on Operating Results; Requests For Information of Local Interest
IL 91-11	Coalbed Methane Regulation
IL 92-11	Experimental Schemes – Release of Information
IL 99-5	The Elimination of the Surface Release of Produced Water

APPENDIX II

ipaa
America's Oil and Gas Producers

Fact Sheet

Internal Revenue Code Section 29 Tax Credit Availability

Section 29 of the Internal Revenue Code provides a tax credit for production of certain nonconventional fuels including gas from coal seams, Devonian shales, and tight formations if produced and sold before Dec. 31, 2002 from a well drilled before 1993. The tax credit currently set at $1.00/Mcf, reduces the regular tax liability dollar-for-dollar and expires Dec. 31, 2002.

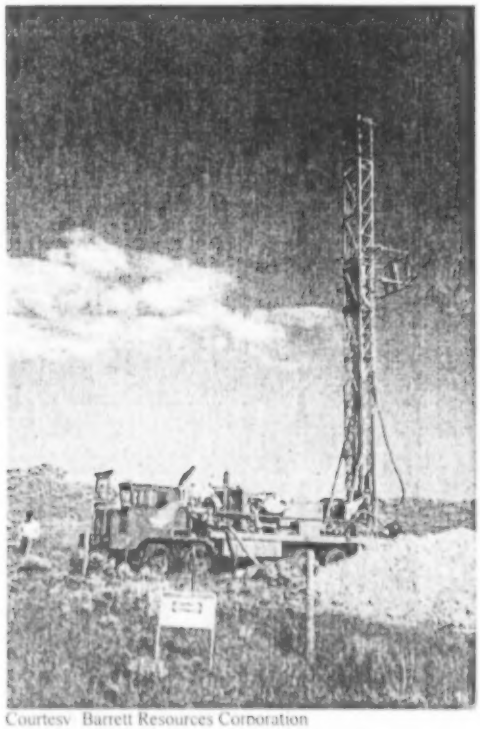
Section 29(c)(2)(A) provides that the determination of whether any gas is produced from coal seams, or a tight formation shall be made in accordance with Section 503 of the National Gas Policy Act of 1978 (NGPA). Under this provision, the Federal Energy Regulatory Commission (FERC) reviewed well determinations that were made by state jurisdictional agencies. The FERC review was not a condition precedent to the qualification of the well's production, but could be obtained retroactively. The Natural Gas Wellhead Decontrol Act of 1989 repealed section 503 of the NGPA. This resulted in FERC's determination that it lacked authority to review state determinations under Section 29.

In an effort to accommodate congressional intent, FERC extended its review process to May 1994 for determination requests filed before 1993. The IRS previous position in Rev Rul. 93-54 found the drilling requirements to qualify for a section 29 credit were met if a taxpayer recompletes into a qualifying formation from a well-bore that was drilled before 1993 and produced from a deeper formation. However, at odds with this previous ruling and clear congressional intent is a judgment in the *True Oil v. Commissioner of Internal Revenue* case that a FERC determination is a prerequisite for a section 29 well determination.

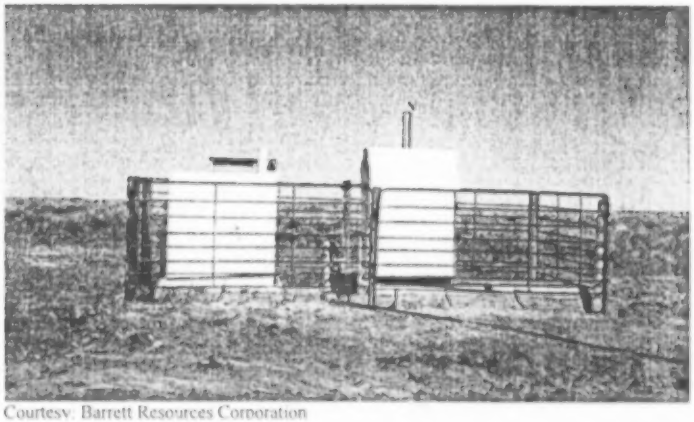
On February 8, 2000, FERC proposed a rule to allow for determinations on well recompletions commenced after January 1, 1993, which comply with Rev. Rul. 93-54. IPAA filed comments with FERC in April 2000 urging expansion of its proposal to include all wells that would qualify under the scope of Section 29.

On July 14 FERC issued a final rule reinstating provisions for well category determinations for certain categories of high-cost gas under NGPA section 107 (Order No. 616). An NGPA determination will allow the gas to be eligible for a tax credit under section 29 of the Internal Revenue Code. The final rule adopts the IPAA position and extends the provisions to all wells spudded before January 1, 1993, and recompletions both before and after that date that could qualify for the section 29 tax credit. The rule also provides for the designation of new tight formations.

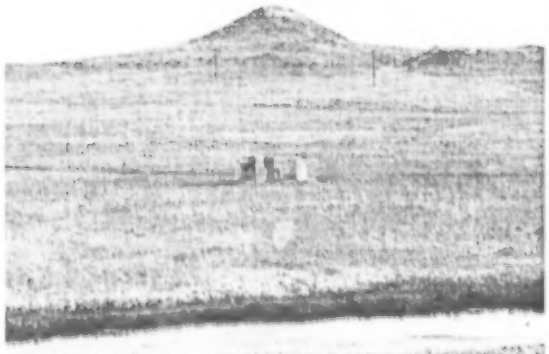
APPENDIX III – Stages of Coalbed Methane Production



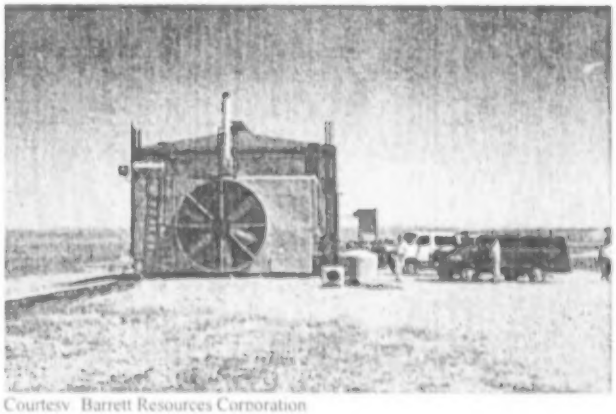
Courtesy: Barrett Resources Corporation



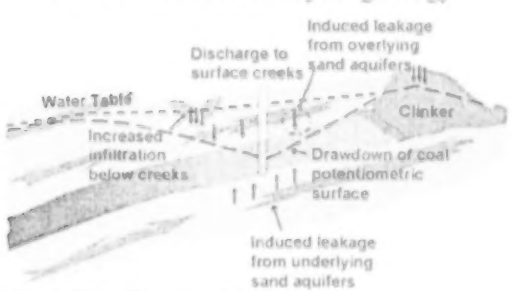
Courtesy: Barrett Resources Corporation



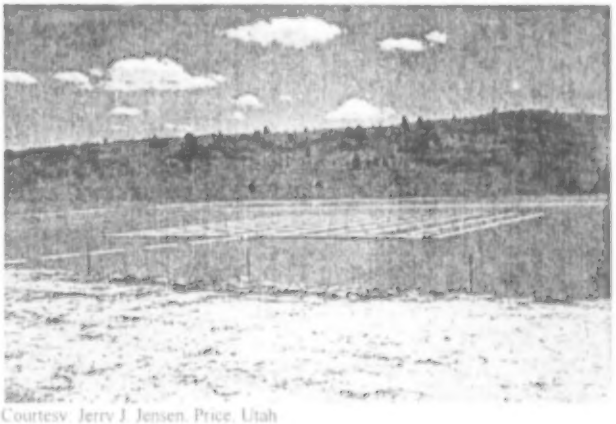
Courtesy: Barrett Resources Corporation



Courtesy: Barrett Resources Corporation


CBM Influences on Hydrogeology
Induced leakage from overlying sand aquifers
Discharge to surface creeks
Water Table
Clinker
Increased infiltration below creeks
Drawdown of coal potentiometric surface
Induced leakage from underlying sand aquifers

Courtesy: Barrett Resources Corporation



Courtesy: Jerry J. Jensen, Price, Utah

APPENDIX IV – Powder River Basin, United States Geological Survey

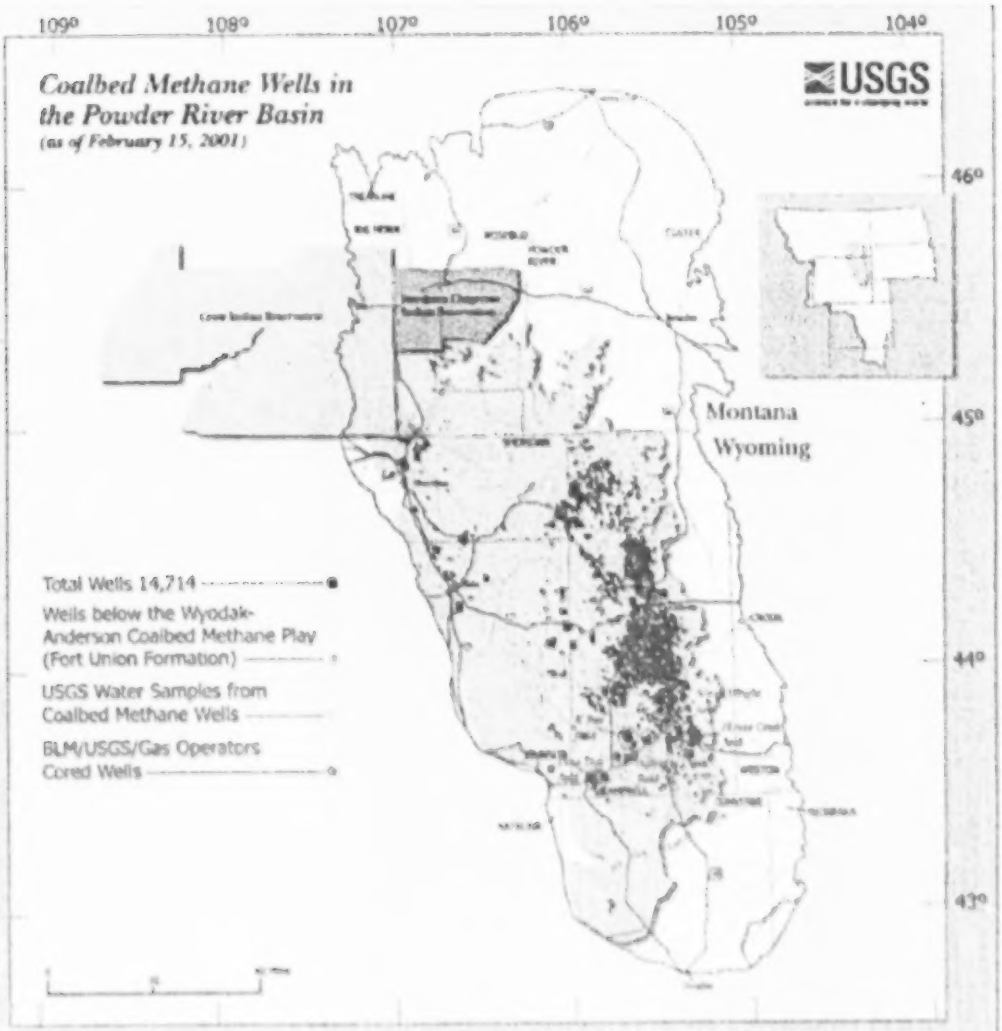


Figure 5

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